CONSTRUCTION PERMIT
for Prevention of Significant Deterioration
OFFICE OF AIR MANAGEMENT

Whiting Clean Energy, Inc.
2155 Standard Avenue
Whiting, Indiana 46394

(herein known as the Permittee) is hereby authorized to construct the facilities listed in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company (herein known as the Permittee) under the provisions of 326 IAC 2-1.1, 326 IAC 2-2, 326 IAC 2-3, 326 IAC 2-5.1, 40 CFR 52.780 and 40 CFR 124, with conditions listed on the attached pages.

Construction Permit No.: CP-089-11194-00449	
Issued by: Paul Dubenetzky, Branch Chief Office of Air Management	Issuance Date:

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SECTION A — SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Management (OAM). The information describing the source contained in conditions A.1 and A.2 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information

The Permittee owns and operates an industrial steam and electric power cogeneration plant.

Responsible Official:	V. Michael Alverson
Source Address:	2155 Standard Avenue, Whiting, Indiana 46394
Mailing Address:	8407 Virginia Street, Merrillville, Indiana 46410
SIC Code:	4911
County Location:	Lake
County Status:	Nonattainment for PM_{10}, SO_2, and ozone (NOx and VOC)
Source Status:	Major PSD Source for PM, NO_2, and CO Major Emission Offset Source for PM_{10}, and ozone (NOx and VOC) One of the 28 Listed Categories (Fossil Fuel-Fired Steam Electric Plant of more than 250 MMBtu per hour)

A.2 Emission Units and Pollution Control Equipment Summary

This new source for Whiting Clean Energy, Inc., relates to the construction and operation of an industrial steam and electric power cogeneration plant consisting of the following equipment:

(a) Two Combustion Turbines:

Heat Input Capacity:	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MWe @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NOx Burners
Stack ID:	CT 1 exhausts through HRSG 1 to Stack 1 CT 2 exhausts through HRSG 2 to Stack 2

(b) Two Supplementary Heat Recovery Steam Generators with Two Duct Burners:

Steam Generating Capacity:	1300 psig
Duct Burner Heat Input Capacity:	821 MMBtu per hour (HHV), each
Fuel Source:	Natural Gas
Control Technology:	Low NOx Burners and Selective Catalytic Reduction (SCR) System for NOx Control
Steam Production Capacity:	580,000 pounds per hour, each, without duct burners 1,188,000 pounds per hour, each, with duct burners

(c) One Condensing Steam Turbine Generator:

Electric Generating Capacity:	213 MWe @ 1,600,000 pounds per hour steam

(d) Induced Draft Cooling Tower:

System Technology:	5 cycle, 10 cell, induced draft cooling tower
Water Circulation Rate:	160,000 gallons per minute non-contact cooling water
Control Technology:	Mist Eliminator for PM Control

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

(a) This stationary source will be required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because it is a major source as defined in 326 IAC 2-7-1(22).

(b) This new source shall apply for a Part 70 (Title V) operating permit within twelve (12) months after this source becomes subject to Title V.

A.4 Acid Rain Permit Applicability [40 CFR 72.30]

(a) This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR 72.30 (Applicability) because the combustion turbines are new units under 40 CR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit has been issued.

Section B **Construction Conditions**

B.1 General Construction Conditions

(a) This permit is based on the data and information submitted by the Permittee. Any change in the design or operation of the plant that could increase emissions or change applicable air pollution control requirements may require that the permit be amended in accordance with 326 IAC 2 as set forth in condition B.4 of this permit.

(b) This permit to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

(c) Notwithstanding Construction Condition B.4, all requirements and conditions of this construction permit shall remain in effect unless modified in a manner consistent with procedures established for modifications of construction permits pursuant to 326 IAC 2 (Permit Review Rules).

(d) When the facility is constructed and placed into commercial operation, the operation conditions required by Section C and Section D shall be met.

B.2 Effective Date of the Permit

Pursuant to 40 CFR Parts 124.15, 124.19 and 124.20, the effective date of this permit will be thirty (30) days from its issuance if comments are received. Three (3) days shall be added to the thirty (30) day period, if service of notice is by mail. If no public comments are received, then the permit shall be effective immediately upon issuance.

B.3 Permit Revocation

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), this permit may be revoked if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

B.4 First Time Operation Permit

This document shall also become a first-time operation permit pursuant to 326 IAC 2-5.1-3 (Permits) when, prior to start of operation, the following requirements are met:

(a) Any modifications required by 326 IAC 2-1.1 and 326 IAC 2-7-10.5 as a result of a change in the design or operation of emissions units described by this permit have been obtained prior to obtaining an Operation Permit Validation Letter.

(b) The attached affidavit of construction shall be submitted to:

Indiana Department of Environmental Management
Permit Administration & Development Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, IN 46206-6015

verifying that the facilities were constructed as proposed in the application and subsequently received approvals from IDEM, OAM.

(1) The facilities covered in the Construction Permit may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM, OAM if the

provisions of 40 CFR Parts 72-80 (Acid Rain Program) are not applicable to such facilities.

(2) If the facilities are subject to the provisions of 40 CFR Parts 72-80 (Acid Rain Program), then the proper Phase II, Acid Rain permit must be issued to such facilities before operation can commence.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) The Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section and attach it to this document.

(e) The operation permit will be subject to annual operating permit fees pursuant to 326 IAC 2-7-19 (Fees).

(f) Pursuant to 326 IAC 2-7-4, the Permittee shall apply for a Title V operating permit within twelve (12) months after the source becomes subject to Title V. This 12-month period starts at the postmarked submission date of the Affidavit of Construction. If the construction is completed in phases, the 12-month period starts at the postmarked submission date of the Affidavit of Construction that triggers the Title V applicability. The operation permit issued shall contain as a minimum the conditions in the Operation Conditions section of this permit.

B.5 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60.7 and 60.8, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

(c) Actual start-up date (within 15 days after such date); and

(d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to IDEM, OAM. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

General Operation Conditions

C.1 General Operation Conditions

(a) This permit is based on the data and information supplied by the Permittee. The Indiana statutes from IC 13 and rules from 326 IAC, quoted in conditions in this permit, are those applicable at the time the permit was issued. The Permittee shall comply with all applicable provisions of IC 13 and 326 IAC.

(b) After obtaining the approval to operate in accordance with Condition B.4 of this permit, the Permittee shall subsequently obtain necessary approvals as required by 326 IAC 2-1.1 and 326 IAC 2-7-10.5.

C.2 Transfer of Permit

(a) In the event that ownership of this industrial steam and electric power co-generation facility is changed, the Permittee shall notify:

Indiana Department of Environmental Management
Permits Branch, Office of Air Management
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

within thirty (30) days of the change. Notification shall include the date or proposed date of said change.

(b) A written notification shall be sufficient to transfer the permit from the current owner to the new owner.

(c) IDEM, OAM shall reserve the right to issue a new permit.

C.3 Permit Revocation

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), this permit to construct and operate may be revoked for any of the following causes:

(a) Violation of any conditions of this permit;

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this permit;

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit;

(d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode; or

(e) For any cause which establishes in the judgment of IDEM, OAM, the fact that continuance of this permit is not consistent with purposes of 326 IAC 2-1.1 (Permit Review Rules).

C.4 Availability of Permit

Pursuant to 326 IAC 2-5.1-3(e)(4), the Permittee shall maintain the applicable permit on the premises of this source and shall make this permit available for inspection by IDEM, OAM, or other public official having jurisdiction.

C.5 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this approval, the Permittee shall prepare and implement Preventive Maintenance Plans (PMPs) upon commercial operation. Commercial operation is defined as the date in which operations produce steam or electricity for sale. The PMPs are comprised of:

   (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

   (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;

   (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that failure to implement the Preventive Maintenance Plan does not cause or contribute to a violation of any emission limitation.

(c) PMPs shall be submitted to IDEM, OAM upon request and shall be subject to review and approval by IDEM, OAM. IDEM, OAM may require the Permittee to revise its Preventive Maintenance Plan whenever lack of proper maintenance causes or contributes to any violation.

C.6 Malfunction Condition

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to IDEM, OAM or appointed representative upon request.

(b) When a malfunction of any facility or emission control equipment occurs which results in an exceedance of the limits of this permit that lasts more than one (1) hour, said condition shall be reported to IDEM, OAM, using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.

(c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

Emission Limitations and Standards

C.7 Opacity Emissions

Pursuant to 326 IAC 5-1-2 (Visible Emissions Limitations), except as provided in 326 IAC 5-1-3 (Temporary Exemptions), visible emissions shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.8 Fugitive Dust Emissions

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.9 Operation of Equipment [326 IAC 2-5.1-3]

Except during periods of startup and shutdown or as otherwise provided in this permit, all air pollution control equipment listed in this permit and used to comply with an applicable requirement shall be operated at all times that an emission unit vented to the control equipment is in operation.

C.10 Stack Height Provisions

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted.

Testing Requirements

C.11 Performance Testing [326 IAC 3-6][326 IAC 2-1.1-11]

(a) Compliance testing on new emission units shall be conducted within 60 days after achieving maximum production rate, but no later than 180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this approval, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAM. A test protocol, except as provided elsewhere in this approval, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The Permittee shall submit a notice of the actual test date to the above address so that it is received at least two weeks prior to the test date.

(b) All test reports must be received by IDEM, OAM within forty-five (45) days after the completion of the testing. An extension may be granted by the IDEM, OAM, if the source submits to IDEM, OAM, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Monitoring Requirements

C.12 Compliance Monitoring [326 IAC 2-1.1-11 and 326 IAC 3-5]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements shall be implemented within 60 days of commercial operation, as defined in Condition C.5, but no later than 180 days after initial startup, except as provided elsewhere in this approval.

C.13 Maintenance of Monitoring Equipment

(a) In the event that a breakdown of the monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this approval until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less than one (1) hour until such time as the continuous monitor is back in operation.

(1) In the event of nitrogen oxide monitor failure, the Permittee shall maintain ammonia feed at the rate at which it was being fed prior to the monitor malfunction. If the Permittee is unable to repair the monitoring equipment, a backup analyzer shall be installed within 48 hours of the time of the initial monitor failure.

(2) In the event of oxygen monitor failure, the Permittee shall maintain the NOx concentration at the same level which it was being held prior to the monitor malfunction. If the Permittee is unable to repair the monitoring equipment, a backup analyzer shall be installed within 48 hours of the initial monitor failure.

(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

(c) The Permittee is not required to operate the continuous emissions monitor when its associated production equipment is not in operation.

C.14 Monitoring Methods

Any monitoring or testing performed to meet the requirements of this permit shall be performed, according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, or other approved methods as specified in this permit.

C.15 Visible Emission Determination

Pursuant to 326 IAC 5, 326 IAC 6, and 326 IAC 12, visible emissions from the source shall be measured using one or both of the following procedures to demonstrate compliance with the opacity limitations:

(a) visible emissions observations performed in accordance with the applicable procedures under 326 IAC 5-1-4 and 40 CFR 60, Appendix A, Method 9; or

(b) continuous opacity monitoring data recorded in accordance with the applicable procedures under 40 CFR 60, Appendix B, Performance Specification 1 and 326 IAC 3-1.1.

A violation determined by one of the above methods shall not be refuted by the other method.

Corrective Actions and Response Steps

C.16 Compliance Monitoring Plan - Failure to Take Response Steps [326 IAC 1-6]

(a) The Permittee is required to implement a compliance monitoring plan to ensure that reasonable information is available to evaluate its continuous compliance with applicable requirements. This compliance monitoring plan is comprised of:

(1) This condition;

(2) The Compliance Determination Requirements in Section D of this approval;

(3) The Compliance Monitoring Requirements in Section D of this approval;

(4) The Record Keeping and Reporting Requirements in Section C (Monitoring Data Availability, General Record Keeping Requirements, and General Reporting Requirements) and in Section D of this approval; and

(5) A Compliance Response Plan (CRP) for each compliance monitoring condition of this approval. CRPs shall be submitted to IDEM, OAM upon request and shall be subject to review and approval by IDEM, OAM. The Permittee shall prepare and implement the CRPs upon commercial operation, as defined in Condition C.5. The CRPs are comprised of:

(A) Response steps that will be implemented in the event that compliance related information indicates that a response step is needed pursuant to the requirements of Section D of this approval; and

(B) A time schedule for taking such response steps including a schedule for devising additional response steps for situations that may not have been predicted.

(b) For each compliance monitoring condition of this approval, appropriate response steps shall be taken when indicated by the provisions of that compliance monitoring condition. Failure to perform the actions detailed in the compliance monitoring conditions or failure to take the response steps within the time prescribed in the Compliance Response Plan, shall constitute a violation of the approval unless taking the response steps set forth in the Compliance Response Plan would be unreasonable.

(c) After investigating the reason for the excursion, the Permittee is excused from taking further response steps for any of the following reasons:

(1) The monitoring equipment malfunctioned, giving a false reading. This shall be an excuse from taking further response steps providing that prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the approval conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the approval, and such request has not been denied or;

(3) An automatic measurement was taken when the process was not operating; or

(4) The process has already returned to operating within “normal” parameters and no response steps are required.

(d) Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken. In the event of an emergency, the provisions of 326 IAC 2-7-16 (Emergency Provisions) requiring prompt corrective action to mitigate emissions shall prevail.

C.17 Actions Related to Noncompliance Demonstrated by a Stack Test

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this approval exceed the level specified in any condition of this approval, the Permittee shall take appropriate corrective actions. The Permittee shall submit a description of these corrective actions to IDEM, OAM, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize emissions from the affected facility while the corrective actions are being implemented. IDEM, OAM shall notify the Permittee within thirty (30) days, if the corrective actions taken are deficient. The Permittee shall submit a description of additional corrective actions taken to IDEM, OAM within thirty (30) days of receipt of the notice of deficiency. IDEM, OAM reserves the authority to use enforcement activities to resolve noncompliant stack tests.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAM that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAM may extend the retesting deadline. Failure of the second test to demonstrate compliance with the appropriate approval conditions may be grounds for immediate revocation of the approval to operate the affected facility.

C.18 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Management
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAM, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAM, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

Record Keeping and Reporting Requirements

C.19 Emission Statement [326 IAC 2-6]

(a) The Permittee shall submit an annual emission statement certified pursuant to the requirements of 326 IAC 2-6, that must be received by April 15 of each year and must comply with the minimum requirements specified in 326 IAC 2-6-4. The annual emission statement shall meet the following requirements:

(1) Indicate actual emissions of criteria pollutants from the source, in compliance with 326 IAC 2-6 (Emission Reporting);

(2) Indicate actual emissions of other regulated pollutants from the source, for purposes of Part 70 fee assessment.

(b) The annual emission statement covers the twelve (12) consecutive month time period starting December 1 and ending November 30. The annual emission statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(c) The annual emission statement required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAM, on or before the date it is due.

C.20 Monitoring Data Availability

(a) With the exception of performance tests conducted in accordance with Section C - Performance Testing, all observations, sampling, maintenance procedures, and record keeping, required as a condition of this approval shall be performed at all times the equipment is operating at normal representative conditions.

(b) As an alternative to the observations, sampling, maintenance procedures, and record keeping of subsection (a) above, when the equipment listed in Section D of this approval is not operating, the Permittee shall either record the fact that the equipment is shut down or perform the observations, sampling, maintenance procedures, and record keeping that would otherwise be required by this approval.

(c) If the equipment is operating but abnormal conditions prevail, additional observations and sampling should be taken with a record made of the nature of the abnormality.

(d) If for reasons beyond its control, the operator fails to make required observations, sampling, maintenance procedures, or record keeping, reasons for this must be recorded.

(1) At its discretion, IDEM, OAM may excuse such failure providing adequate justification is documented and such failures do not exceed five percent (5%) of the operating time in any quarter.

(2) Temporary, unscheduled unavailability of staff qualified to perform the required observations, sampling, maintenance procedures, or record keeping shall be considered a valid reason for failure to perform the requirements stated in (a) above.

C.21 General Recordkeeping Requirements

(a) Records of all required monitoring data and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years and available upon the request of an IDEM, OAM representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available within a reasonable time upon request. If the Commissioner makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Records of required monitoring information shall include, where applicable:

(1) The date, place, and time of sampling or measurements;

(2) The dates analyses were performed;

(3) The company or entity performing the analyses;

(4) The analytic techniques or methods used;

(5) The results of such analyses; and

(6) The operating conditions existing at the time of sampling or measurement.

(c) Support information shall include, where applicable:

(1) Copies of all reports required by this approval;

(2) All original strip chart recordings for continuous monitoring instrumentation;

(3) All calibration and maintenance records;

(4) Records of preventive maintenance shall be sufficient to demonstrate that failure to implement the Preventive Maintenance Plan did not cause or contribute to a violation of any limitation on emissions or potential to emit. To be relied upon subsequent to any such violation, these records may include, but are not limited to: work orders, parts inventories, and operator's standard operating procedures. Records of response steps taken shall indicate whether the response steps were performed in accordance with the Compliance Response Plan required by Section C - Compliance Monitoring Plan - Failure to take Response Steps, of this approval, and whether a deviation from an approval condition was reported. All records shall briefly describe what maintenance and response steps were taken and indicate who performed the tasks.

(d) All record keeping requirements not already legally required shall be implemented upon commercial operation.

C.22 General Reporting Requirements

(a) The reports required by conditions in Section D of this approval shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(b) Unless otherwise specified in this approval, any notice, report, or other submission required by this approval shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAM on or before the date it is due.

(c) Unless otherwise specified in this approval, any quarterly report shall be submitted within thirty (30) days of the end of the reporting period.

(d) The first report shall cover the period commencing on the date of commercial operation and ending on the last day of the reporting period.

SECTION D.1 FACILITY OPERATION CONDITIONS

(a) Two Combustion Turbines (CTs):

Heat Input Capacity:	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MWe @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NOx Burners and Selective Catalytic Reduction
Stack ID:	CT 1 exhausts through HRSG 1 to Stack 1 CT 2 exhausts through HRSG 2 to Stack 2

(b) Two Supplementary Heat Recovery Steam Generators (HRSGs) with Two Duct Burners:

Steam Generating Capacity:	1300 psig
Duct Burner Heat Input Capacity:	821 MMBtu per hour (HHV), each
Fuel Source:	Natural Gas
Control Technology:	Low NOx Burners and Selective Catalytic Reduction
Steam Production Capacity:	580,000 pounds per hour, each, without duct burners 1,188,000 pounds per hour, each, with duct burners

(c) One Condensing Steam Turbine Generator:

Electric Generating Capacity:	213 MWe @ 1,600,000 pounds per hour steam

(d) Induced Draft Cooling Tower:

System Technology:	5 cycle, 10 cell, induced draft cooling tower
Water Circulation Rate:	160,000 gallons per minute non-contact cooling water
Control Technology:	Mist Eliminator

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 Particulate Matter (PM and PM_{10}) Emission Limitations

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM emissions from each combustion turbine stack shall not exceed 0.0045 pounds per MMBtu which is equivalent to 7.8 pounds per hour.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.0045 pounds per MMBtu which is equivalent to 11.5 pounds per hour.

(c) Pursuant to 326 IAC 12 and 40 CFR 60, Subpart Da (New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units), each steam generating unit shall comply to the following:

(1) The opacity from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

(2) The PM emissions from each duct burner shall not exceed 0.03 pounds per MMBtu heat input.

(d) Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC 2-3 (Emission Offset Requirements), the opacity from each combustion turbine stack shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

(e) Pursuant to 326 IAC 6-1-2 (Nonattainment Area Particulate Limitations), each steam generating unit shall comply with the following:

(1) Pursuant to 326 IAC 6-1-2(a), the PM emissions from each combustion turbine stack shall not exceed 0.03 grains per dry standard cubic feet.

(2) Pursuant to 326 IAC 6-1-2(b)(5), PM emissions associated with the duct burner from each combustion turbine stack, shall not exceed 0.01 grains per dry standard cubic feet.

(f) To avoid the requirements of 326 IAC 2-3 (Emission Offset Requirements) for PM_{10}:

(1) the PM_{10} (filterable + condensible) emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 11.5 pounds per hour; and

(2) the combined natural gas fuel usage from the duct burners shall not exceed 8,052 MMSCF per year, based on a 12 consecutive month period.

D.1.2 Nitrogen Oxides (NO_X) Emission Limitations

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC 2-3 (Emission Offset Requirements), each combustion turbine/steam generating unit shall comply with the following:

(1) During normal operation (50 percent load or more), the NO_X emissions from each combustion turbine stack shall not exceed 3.0 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, which is equivalent to 19.5 pounds NO_X per hour at ISO conditions.

(2) During normal operation (50 percent load or more), the NO_X emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 3.0 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, which is equivalent to 38.0 pounds NO_X per hour at ISO conditions.

(3) During periods of startups or shutdowns (less than 50 percent load), the NOx emissions from each combustion turbine stack shall not exceed 70 ppmvd at 15 percent oxygen. The startup or shutdown period shall not exceed two (2) hours. The duct burners shall not be operated until normal operation begins.

(4) Each combustion turbine shall be equipped with dry low-NO_X burners and operated using good combustion practices to control NO_X emissions.

(5) A selective catalytic reduction (SCR) system shall be installed and operated at all times, except during periods of startup/shutdown, to control NO_X emissions.

(b) Pursuant to 326 IAC 12 and 40 CFR 60, Subpart Da (NSPS for Electric Utility Steam Generating Units), each duct burner shall not exceed 1.6 pounds/MW-hr gross energy output on a 30-day rolling average.

(c) Pursuant to 326 IAC 12 and 40 CFR 60, Subpart GG (NSPS for Stationary Gas Turbines), the NOx emissions from each combustion turbine shall not exceed the following:

$$STD = 0.0075 \times ((14.4)/Y) + F$$

where:

STD	=	Allowable NOx percent by volume @ 15% O_2, dry basis
Y	=	Heat Rate not to exceed 14.4 kilojoules per watt-hr
F	=	NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

D.1.3 Carbon Monoxide (CO) Emission Limitations

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each steam generating unit shall comply with the following:

(1) During normal operation (50 percent load or more), the CO emissions from each combustion turbine stack shall not exceed 0.016 pounds per MMBtu, which is equivalent to 28.0 pounds CO per hour.

(2) During normal operation (50 percent load or more), the CO emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.037 pounds per MMBtu, which is equivalent to 93.7 pounds CO per hour.

(3) During periods of startups or shutdowns (less than 50 percent load), the CO emissions from each combustion turbine stack shall not exceed 110 ppmvd at 15 percent oxygen. The startup or shutdown period shall not exceed two (2) hours. The duct burners shall not be operated until normal operation begins.

(4) Good combustion practices shall be applied to minimize CO emissions.

D.1.4 Sulfur Dioxide (SO_2) Emission Limitations

(a) Pursuant to 326 IAC 12 and 40 CFR 60, Subpart Da (NSPS for Electric Utility Steam Generating Units), each duct burner shall not exceed 0.20 pounds SO_2 per MMBtu heat input, determined on a 30-day rolling average basis.

(b) Pursuant to 326 IAC 12 and 40 CFR 60, Subpart GG (NSPS for Stationary Gas Turbines), each combustion turbine shall not exceed 0.015 volume percent SO_2 at 15 percent oxygen (dry basis) and the natural gas fuel shall not exceed 0.8 percent sulfur by weight.

(c) Pursuant to 326 IAC 7-1.1-2 (SO_2 Emission Limitations), each combustion turbine and its associated duct burner shall not exceed 6.0 pounds SO_2 per MMBtu.

(d) To avoid the requirements of 326 IAC 2-3 (Emission Offset Rules), the total SO_2 emissions from the combustion turbines and duct burners combined shall not exceed 22.8 pounds SO_2 per hour. This limitation shall satisfy the requirements of 326 IAC 12 and 326 IAC 7-1.1-2.

D.1.5 Volatile Organic Compound (VOC) Emission Limitations

(a) Pursuant to 326 IAC 8-1-6 (VOC BACT Requirements) and 326 IAC 2-3 (Emission Offset Requirements), the following requirements must be met:

(1) The VOC emissions from each combustion turbine stack shall not exceed 0.0016 pounds per MMBtu which is equivalent to 2.8 pounds VOC per hour.

(2) The VOC emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.0046 pounds per MMBtu which is equivalent to 11.8 pounds VOC per hour.

(3) Good combustion practices shall be implemented to minimize VOC emissions.

D.1.6 Emission Reduction Credits

Pursuant to 326 IAC 2-3-1(j) and 326 IAC 2-3-3(a)(5), the source must offset ozone (VOC and NO_X) emissions in accordance with the following:

(a) The total VOC emission offsets required as a result of this project is 90.4 tons per year. The emission reduction credits shall be obtained from shutdown of the Lubes Unit at BP Amoco Oil (089-00003). If other emission reduction credits are relied upon after issuance of this permit, this permit must be amended to identify and validate those emission reduction credits. All emission reduction credits must be validated by OAM and creditable prior to startup of the source.

(b) The total NO_X emission offsets required as a result of this project is 341 tons per year. The emission reduction credits shall be obtained from shutdown of the 76" Hot Strip Mill at Ispat Inland, Inc. (089-00316). If other emission reduction credits are relied upon after issuance of this permit, this permit must be amended to identify and validate those emission reduction credits. All emission reduction credits must be validated by OAM and creditable prior to startup of the source.

D.1.7 Formaldehyde Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the formaldehyde emissions from each combustion turbine stack shall not exceed 0.0005 pounds of formaldehyde per MMBtu. The combined emissions from each combustion turbine stack shall not exceed 10 tons per year.

D.1.8 Ammonia Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the ammonia emissions from each combustion turbine stack shall not exceed 10 ppm.

D.1.9 Annual Emission Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC 2-3 (Emission Offset Requirements), the annual source emissions, including startup and shutdown operations, shall not exceed 262 tons of NOx per year and 571 tons of CO per year, based on a 12 consecutive month period.

D.1.10 Operation Limitations

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC 2-3 (Emission Offset Requirements), the combined natural gas fuel usage from the duct burners shall not exceed 8,052 MMSCF per year, based on a 12 consecutive month period. This limitation shall also demonstrate that PM10 is not subject to 326 IAC 2-3 (Emission Offset Requirements).

(b) Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC 2-3 (Emission Offset Requirements), each combustion turbine shall not exceed a heat input rate of 1735 MMBtu per hour, determined on a 30-day rolling average basis. This averaging time shall only account for those periods that the combustion turbine is in operation.

D.1.11 New Source Performance Standards

The combustion turbines and duct burners shall comply with the provisions of 40 CFR 60, Subpart A (General Provisions), 40 CFR 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units), and 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) which are incorporated by reference in 326 IAC 12-1.

D.1.12 Preventive Maintenance Plan

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for each combustion turbine and its control device.

Compliance Determination and Monitoring:

D.1.13 Performance Testing

(a) Pursuant to 326 IAC 2-1.1-11, 326 IAC 2-2, 326 IAC 2-3, and 326 IAC 12, the following compliance stack tests for each combustion turbine stack shall be performed within 60 days of commercial operation, as defined in Condition C.5, but no later than 180 days after initial start-up:

(1) Combustion Turbines (Normal Operation - 50 percent load or more) - PM, opacity, and VOC emission limits established in D.1.1(a), (c)(1), (d), (e)(1) and D.1.5(a)(1) shall be demonstrated for each combustion turbine at maximum load;

(2) Combustion Turbines (Normal Operation - 50 percent load or more) - NOx and CO emission limits of D.1.2(a)(1) and D.1.3(a) shall be demonstrated at four points in the normal operating range of each combustion turbine, including the minimum point in the range and peak load;

(3) Combustion Turbines (Cold Startup Operation - less than 50 percent load) - NOx and CO emission limits of D.1.2(a)(3) and D.1.3(a)(3) shall be demonstrated for each combustion turbine during startup mode; and

(4) Combustion Turbines and Duct Burners (Normal Operation - 50 percent load or more) - PM, PM_{10}, opacity, NOx, CO, VOC, formaldehyde and ammonia emission limits established in D.1.1(b), (c)(2), (d), (e)(2), (f)(1), D.1.2(a)(2), D.1.3(b), D.1.5(a)(2), D.1.7 and D.1.8 shall be demonstrated for each combustion turbine at maximum load when its associated duct burners are in operation.

(b) Pursuant to 326 IAC 3-5, the Permittee shall conduct performance tests on each combustion turbine stack to certify the continuous emission monitoring (CEM) systems for NOx.

(c) A certified CEM system may be used in lieu of a compliance stack test.

(d) EPA Method 9 opacity tests shall be performed concurrently with the PM and PM_{10} compliance tests, unless meteorological conditions require rescheduling the opacity tests to another date.

(e) IDEM, OAM retains the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.1.14 Continuous Emission Monitoring

(a) Pursuant to 326 IAC 2-2, 326 IAC 2-3, 326 IAC 3-5, and 326 IAC 12, the Permittee shall continuously monitor and record the following parameters from each combustion turbine stack to demonstrate compliance with the limitations and operation standards required by Operation Conditions D.1.2:

(1) nitrogen oxide concentration; and

(2) oxygen concentration.

(b) The continuous monitoring systems shall be installed and operational prior to conducting the performance tests. A monitoring protocol shall be performed in accordance with the applicable procedures under 40 CFR 60, Appendix B, Performance Specification 1 and 326 IAC 3-5 and shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

within 60 days of commercial operation, as defined in Condition C.5, but no later than 180 days after initial startup. Verification of operational status shall, as a minimum, include completion of the manufacturer written requirements or recommendations for installation, operation, and calibration of the device.

D.1.15 Natural Gas Monitoring

Upon commercial operation, as defined in Condition C.5, the Permittee shall monitor the following parameters for natural gas on a calendar month basis, unless otherwise specified in 40 CFR 60.334(b), to demonstrate compliance with Operation Conditions D.1.2(b) and (f)(2), D.1.3(a), D.1.4(a) and (c), D.1.5(a) and D.1.10:

(a) hourly natural gas flowrate to each combustion turbine and duct burner;

(b) average sulfur content;

(c) heat content;

(d) natural gas fuel consumption; and

(e) sulfur dioxide emission rate in pounds per million Btu.

Recordkeeping and Reporting Requirements:

D.1.16 Recordkeeping Requirement

The Permittee shall maintain records of the parameters stated in Operation Conditions D.1.6, D.1.10, D.1.13, D.1.14, and D.1.15 to demonstrate compliance with Operation Conditions D.1.1, D.1.2, D.1.3, D.1.4, D.1.5, D.1.7, D.1.8, and D.1.9.

D.1.17 Reporting Requirement

The Permittee shall submit the following information on a quarterly basis:

(a) records of excess NOx emissions (defined in 326 IAC 3-5-7) from the continuous emissions monitoring system for each parameter described in Operation Condition D.1.14 to demonstrate compliance with Operation Condition D.1.2;

(b) records of excess SO_2 emissions (defined in 40 CFR 60.334(c)(2)) for the parameter described in Operation Condition D.1.15(b) to demonstrate compliance with Operation Condition D.1.4(b);

(c) monthly natural gas fuel usage records as required by Operation Condition D.1.15(d) to demonstrate compliance with Operation Condition D.1.1(f)(2) and D.1.10; and

(d) daily records of the annual NOx and CO emission records as required by Operation Condition D.1.9 to demonstrate compliance with Operation Condition D.1.6 and PSD and Emission Offset Requirements pursuant to 326 IAC 2-2 and 326 IAC 2-3, respectively.

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR MANAGEMENT
FAX NUMBER - 317 233-5967

This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE: IT HAS POTENTIAL TO EMIT 25 LBS/HR PARTICULATES ?_____, 100 LBS/HR VOC ?_____, 100 LBS/HR SULFUR DIOXIDE ?_____ OR 2000 LBS/HR OF ANY OTHER POLLUTANT ?_____ EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION ________.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _______ OR, PERMIT CONDITION # _______ AND/OR PERMIT LIMIT OF _______________

THIS INCIDENT MEETS THE DEFINITION OF 'MALFUNCTION' AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY:____PHONE NO. ( )__________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. ________________ AFS PLANT ID: ________________ AFS POINT ID: ________________ INSP: _________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:____
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 20____ ____ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ____

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 20____ _______________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER: ______________________________________

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: ____________________________________
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE ESSENTIAL*SERVICES:_____________________________________
CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS:____________________________________
CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT:__________________________
INTERIM CONTROL MEASURES: (IF APPLICABLE)____
MALFUNCTION REPORTED BY: ____________________________________TITLE:_______________________________
(SIGNATURE IF FAXED)
MALFUNCTION RECORDED BY:___________________________DATE:_________________TIME:___________________

REV 3/96 FAX NUMBER - 317 233-5967 *SEE REVERSE

Please note - This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

326 IAC 1-6-1 Applicability of rule

Sec. 1. The requirements of this rule (326 IAC 1-6) shall apply to the owner or operator of any facility which has the potential to emit twenty-five (25) pounds per hour of particulates, one hundred (100) pounds per hour of volatile organic compounds or SO2, or two thousand (2,000) pounds per hour of any other pollutant; or to the owner or operator of any facility with emission control equipment which suffers a malfunction that causes emissions in excess of the applicable limitation.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. (Air Pollution Control Board; 326 IAC 1-2-39; filed Mar 10, 1988, 1:20 p.m. : 11 IR 2373)

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown. If this item is checked on the front, please explain rationale:

____
____
____

Indiana Department of Environmental Management
Office of Air Management
Compliance Data Section
Quarterly Report

Company Name: Whiting Clean Energy, Inc.
Location: 2155 Standard Avenue, Whiting, Indiana 46394
Permit No.: CP 089-11194-00449
Source/Facility: Duct Burner 1 and Duct Burner 2
Limits: 8,052 MMSCF per year, based on a 12 consecutive month period

YEAR: _______________

Month	Facility	Fuel Usage this Month, MMSCF	Fuel Usage Last 12 Months, MMSCF	Fuel Usage Limit, MMSCF/12 consecutive month period
	Duct Burners 1 + 2			8052
	Duct Burners 1 + 2			8052
	Duct Burners 1 + 2			8052

Submitted by: ____

Title / Position: ____

Signature: ____

Date: ____

Phone: ____

Indiana Department of Environmental Management
Office of Air Management
Compliance Data Section
Quarterly Report

Company Name: Whiting Clean Energy, Inc.
Location: 2155 Standard Avenue, Whiting, Indiana 46394
Permit No.: CP 089-11194-00449
Source/Facility: Combustion Turbines and Duct Burners
Limits: 262 tons NOx per year, based on a 12 consecutive month period and
571 tons CO per year, based on a 12 consecutive month period

YEAR: _______________

Month	Facility*	Pollutant	Emissions this Month, tons	Annual Emissions Last 12 Months, tons	Emmission Limit, tons/12 consecutive month period
	Combustion Turbines and Duct Burners	NOx			262
		CO			571
	Combustion Turbines and Duct Burners	NOx			262
		CO			571
	Combustion Turbines and Duct Burners	NOx			262
		CO			571

* This limitation includes startup, shutdown and normal operations. Emissions from startup and shutdown operations shall be determined by multiplying the ppm data collected from a compliance stack test or CEM system by the maximum theoretical flow rate for startup and shutdown operations.

Submitted by: ____

Title / Position: ____

Signature: ____

Date: ____

Phone: ____

Indiana Department of Environmental Management
Office of Air Management

Addendum to the
Technical Support Document for New Construction and Operation

Source Name: **Whiting Clean Energy, Inc.**
Source Location: **2155 Standard Avenue, Whiting, Indiana**
County Location: **Lake**
Construction Permit No.: **CP-089-11194-00449**
SIC Code: **4911**
Permit Reviewer: **Michele Williams**

On June 3, 2000, the Office of Air Management (OAM) had a notice published in *The Times* in Munster, Indiana and *Gary Post Tribune* in Gary, Indiana, stating that Whiting Clean Energy, Inc., had applied for a Prevention of Significant Deterioration (PSD) permit for the construction of an industrial steam and electric power cogeneration plant consisting of two combustion turbines with a nominal heat input rate of 1,735 MMBtu per hour (HHV) @ ISO conditions, each, and two supplementary heat recovery steam generators with two duct burners with a nominal heat input rate of 821 MMBtu per hour (HHV) @ ISO conditions, each. The detailed description of equipment can be found in the construction permit for Prevention of Significant Deterioration.

The notice also stated that OAM proposed to issue a permit for this installation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

The IDEM, OAM has made the following clarifications, additions or changes to the proposed construction permit:

Clarification 1: New Source Toxics Control Rule

On Page 6 of the Technical Support Document, the IDEM, OAM identified the repealed rule cite (326 IAC 2-1-3.4) for the New Source Toxics Control Rule. The current rule cite for the New Source Toxics Control Rule should be 326 IAC 2-4.1. Although the rule cite changed, the information contained in the New Source Toxics Control Rule is the same.

The New Source Toxics Control Rule incorporates by reference the federal Section 112(g) rule and requires new major sources of hazardous air pollutant (HAP) emissions to install the maximum achievable control technology (MACT). MACT must be determined on a case-by-case basis for each proposed new construction. However, this rule exempts “electric utility steam generating units” from applicability and the case-by-case MACT determinations because EPA considers CAA Sec. 112(n)(1) as instruction to exempt such units from regulation under Sec. 112 pending the results of a utility health hazards study currently being performed (see 61 FR 68387).

Recently, EPA has clarified how stationary combustion turbines are subject to a case-by-case MACT determination under Sec. 112(g) in light of the exemption for electric utility steam generating units. The EPA proposed (4/21/00) and issued a final (5/25/00) interpretive rule to clarify that new and reconstructed combustion turbines are not defined as electric utility steam generating units, and therefore are subject to case-by-case MACT review if the combustion turbine is a major source of HAP emissions, regardless of whether it is part of a combined cycle system.

EPA made some significant changes to its interpretive rule between proposal and final issuance. When the Whiting project was reviewed by IDEM, OAM for public notice, the proposed interpretive rule was used to determine if the case-by-case MACT review was required. Upon review of the final rule, the OAM identified clarifications to the applicability requirements. Therefore, the IDEM, OAM performed the following reevaluation of the Whiting project utilizing the final interpretive rule.

According to the final interpretive rule:

> "If the waste heat recovery unit in a combined cycle system operates with duct burners, and more than one-third of the potential electrical output capacity of the duct burners and more than 25 MW of the electrical output provided by the duct burners are ~~sold~~ provided to any utility power distribution system for sale, then the waste heat recovery unit is an electric utility steam generating unit and is not subject to case-by-case MACT determinations. . . . " (see 65 FR 34011)

All of the electricity (i.e., from the combustion turbine generators and steam turbine generator) generated by Whiting, except parasitic losses, is directed to the grid.

The project's host site agreement with a refinery requires Whiting to be capable of meeting a potential maximum steam requirement of 1,100,000 lb/hr at all times. The design steam output from the two combined cycle units, without the duct burners in operation, is 1,148,000 lb/hr. As such, during normal operation, no duct firing is required to meet the steam requirements included in the host site agreement. The reason for the duct burners is to: 1) meet the host site steam demand when a combustion turbine is down, and 2) generate electricity via the steam turbine generator. Some level of duct firing will be required, however, to meet the refinery's steam needs during planned and unplanned combustion turbine outages. The most conservative (i.e., highest) estimate of this is 10 percent of the time based on the amount of annual maintenance required and the projected availability of the combustion turbines and heat recovery steam generators. During these periods it should be noted that the refinery steam demand will most likely not be the host site agreement~~s~~ maximum. Additionally, planned outages will be scheduled during the summer when the refinery's steam requirements are at its minimum. Thus, the 10 percent is a very conservative estimate of when the duct burners will be fired to generate steam for a non-electric generating usage. Any duct burner firing outside of this usage will be directed at either keeping a minimum steam flow rate through the steam generating turbine to keep it warm or at the generation of electricity for distribution to the electric utility grid.

The potential electric generating capacity (PEOC) is defined in 40 CFR 72, Appendix D as follows:

PEOC (MW) = (Maximum Fuel Flow MMBtu/hr) x (1,000,000 Btu/1MMBtu) x (33%) x (1 kw-hr/3,413 Btu) x (1MW/1000kw)

The design heat input for the each of each duct burner is 821.3 MMBtu/hr. Thus, on an hourly basis the PEOC for the duct burners is 158 MW. Annually the duct burners are permitted to operate no more than 5000 hr/yr. As such, on an annual basis the PEOC is 794,107 MW (i.e., 5000 x 158). Current estimates associated with the design of the project indicate that it will be profitable to duct fire the combined cycle units for at least 2000 hrs/yr for the purpose of generating electricity. The projected annual electric output associated with the duct burners is therefore 317,643 MW (i.e., 2000 x 158). Thus, 40 percent of the duct burner PEOC is projected to be used to supply electricity for distribution to the grid. Therefore, the duct burners are not subject to the requirements of the New Source Toxics Control Rule because the duct burners are considered electric steam generating units.

Because the duct burners are not subject to the New Source Toxics Control Rule, the HAP emissions from the duct burners should be evaluated separately from the HAP emissions generated by the combustion turbines. Based on the HAP emission calculations provided in Appendix A of the Technical Support Document, the combustion turbines are not subject to the case-by-case MACT requirements of the New Source Toxics Control Rule because the HAP emissions do not exceed the major source threshold levels (Single HAP # 10 tons per year and Combined HAPs # 25 tons per year). The permit conditions relating to specific HAP compounds are not affected by the outcome of the above analysis.

Clarification 2: Supporting Calculations of Emission Reduction Credits

Attachment 1 provides supporting calculations for the Emission Reduction Credits from BP Amoco - Whiting Refinery and Ispat Inland, Inc. These calculations have been provided for informational purposes to supplement the emission offset (326 IAC 2-3) discussion in the “State and Federal Rule Applicability” section of the Technical Support Document (Page 7 of 15).

Emission Reduction Credit Review

The Office of Air Management (OAM) has performed the following emission reduction credit review for the proposed industrial steam and electric power co-generation plant to be owned and operated by Whiting Clean Energy, Inc. (Whiting), located in Whiting, Indiana. This review is necessary to meet the requirements of the Emission Offset program pursuant to 326 IAC 2-3. The following emission reduction credits must be acquired prior to the operation of the proposed Whiting project and are being obtained from the following sources:

Source	Source Air Permit ID	Facility	Pollutant, tons/year	
			NO_x	VOC
BP Amoco - Whiting	089-00003	Lubes Unit		90.4
Ispat Inland, Inc.	089-00316	76" Hot Strip Mill	341	

(A) BP Amoco Oil - Whiting Refinery - VOC Emission Reduction Credit Review

The VOC emission reduction credits have been generated by the shutdown of the Lubes Unit at the BP Amoco Oil - Whiting Refinery located in Whiting, Indiana. The emissions from the Lubes Unit are fugitive sources of emissions. Amoco is one of the 28 listed categories, therefore the fugitive emissions can be used as emission reduction credits because fugitives must be counted toward PSD applicability.

The entire Lubes Unit, identified in Operation Permit Nos. 45-08-93-0563, 45-08-93-0564, 45-08-93-0565, 45-08-93-0569, and 45-08-93-0570 stopped operations in December of 1998. The actual emissions from this shutdown are creditable because the shutdown occurred within the 5-year contemporaneous period.

The emission reduction credits are determined using the most recent representative 2-year baseline period. The most recent available data from the Lubes Unit at the Amoco facility is 1997 and 1998. Since the component equipment did not change in 1997 and 1998, the annual emission calculations from the component equipment leaks are the same. The following summary table represents the available emission reduction credits from the following facilities of the Lubes Unit:

Lubes Unit Equipment	Operation Permit No.	Total VOC ERCs from Equipment (tons/year)	Total VOC ERCs sold to Whiting (tons/year)
No. 37 Pipe Still	45-08-93-0569	67.4	67.4
Heater to No. 37 Pipe Still	45-08-93-0563	0.94	0.94
Solvent Extraction Unit (NMP)	45-08-93-0569	59.8	59.8
Heaters to Solvent Extraction Unit	45-08-93-0564 45-08-93-0565	1.08	1.08
Methyl Ethyl Ketone (MEK) Dewaxing Unit	45-08-93-0569	394	182
Hydro Finishing (HiFi) Lubes Unit	45-08-93-0569	61.0	61.0

Grease Works Unit	45-08-93-0569	56.1	9.8
Heaters to the Grease Works Unit	45-08-93-0564	0	0
Available VOC Emission Reduction Credits (tons/yr):		640	382
Required VOC Emission Reduction Credits for Whiting:		---	90.4
Total Remaining VOC Emission Reduction Credits:		258 (Amoco)	291.6 (Whiting)

Amoco is required under 326 IAC 2-6 to annually submit an emission statement of actual emissions from its source. Traditionally, the annual emission statements are used to quantify actual emissions for netting and emission offset projects. However, the annual emission statements from Amoco identified all fugitive sources as one emission point. Therefore, the OAM accepted the data from the Toxic Chemical Release Inventory (TRI) required under the Resource Conservation Recovery Act (RCRA) to quantify actual emissions from each of the fugitive sources.

The TRI data was calculated using source specific testing data. The *Protocol for Equipment Leak Emission Estimates,* an EPA guidance document, was used to develop the source specific testing data. Upon review, the OAM accepted the source specific testing data. The emission data is included in Attachment 1-A.

The emissions from each of the heaters of the Lubes Unit were calculated using EPA AP-42 emission factors. The annual emission statements were used to quantify the actual emissions from the heaters of the Lubes Unit. The emission calculations are included in Attachment 1-A.

(B) Ispat Inland, Inc. - NOx Emission Reduction Credit Review

The NOx emission reduction credits have been generated by the shutdown of the 76" Hot Strip Mill at the Ispat Inland located in Whiting, Indiana. The 76" Hot Strip Mill stopped operations in 1995. The emission reduction credits from the shutdown of the 76" Hot Strip Mill were determined using the most recent representative 2-year baseline period. The following summary table represents the available emission reduction credits from the following facilities of the 76" Hot Strip Mill:

Equipment - Pollutant	1994 Actual Emissions (tons/year)	1995 Actual Emissions (tons/year)	Available NOx Emission Reduction Credits (tons/year)
76" Hot Strip Mill	366.2	341.6	354
Required NOx Emission Reduction Credits for Whiting Project (tons/year):			341

Ispat Inland is required under 326 IAC 2-6 to annually submit an emission statement of actual emissions from its source. The annual emission statements for 1994 and 1995 were used to quantify actual emissions from the plant. The emission calculation summaries are included in Attachment 1-B.

Attachment 1-A

VOC Emission Calculations/VOC Emission Data for the Lubes Unit at BP Amoco Oil

The lubes unit is made up of both fugitive sources and point sources of emissions. The point sources include all of the heater components associated with the Lubes Unit. The fugitive sources include component equipment leaks from valves, compressors, and pumps at the Lubes Unit.

A. Point Sources of VOC Emissions from the Lubes Unit

1. Heater to No. 37 Pipe Still
2. Heaters to Solvent Extration Unit (NMP)
3. Heaters to the Grease Works Unit - These heaters were not used in 1997/1998 according to the Emission Statement Reports

Point Source	No. 37 Pipe Still Heater	NMP Heaters
Unit Size, MMBtu/hr	108	147
AP-42 VOC Emission Factor, lb/mmcf	5.5	5.5
1997 Operation Usage, hrs/yr	2150	1950
1997 VOC Emissions, tons/yr	0.63	0.77
1998 Operation Usage, hrs/yr	4250	3500
1998 VOC Emissions, tons/yr	1.24	1.39
Average VOC Emissions, tons/yr	0.94	1.08

Methodology: EPA AP-42 Emission Factors are from Chapter 1.4, Table 1.4-2, Version 3/98
Actual Emissions (tons/yr) = Heat Input Rate (MMBtu/hr) x Emission Factor (lb/MMcf) x (MMcf/1020 MMBtu) x (ton/2000 lbs) x Actual Operation (hrs/yr)

B. Fugitive Sources of VOC Emissions from the Lubes Unit

The component equipment did not change in 1997 and 1998, therefore, the annual emission calculations from the component equipment leaks are the same.

Fugitive Source	VOC Emissions (tons/year)	Emission Factor Sources
No. 37 Pipe Still Equipment:		
H2-37 PS	6.01	1995 Protocol for Equipment Leak Emission Estimates and Leak Detection and Repair (LDAR) Program
HVGO-37 PS	13.4	
NMP-37 PS	13.4	
Propane REFR-37 PS	7.84	
Raffinate-37 PS	13.4	
White-37 PS	13.4	
Solvent Extration Unit (NMP) Equipment:		
H2-NMP	6.23	1995 Protocol for Equipment Leak Emission Estimates and Leak Detection and Repair (LDAR) Program
HVGO-NMP	13.4	
NMP-NMP	13.4	
Raffinate-NMP	13.4	
White-NMP	13.4	
MEK Dewaxing Unit Equipment:		
Tank	12.6	GC Testing Analysis for Tank Estimates
Fugitive Losses	381	Mass Balance Calculations for Fugitive Losses
Hydro Finishing (HiFi) Lube Equipment:		
H2-HiFi	5.94	1995 Protocol for Equipment Leak Emission Estimates and Leak Detection and Repair (LDAR) Program
NMP-HiFi	14.5	
Propane REFR-HiFi	8.22	
Raffinate-HiFi	14.8	
White-HiFi	17.5	
Grease Works Unit Equipment:		
H2-Grease	8.14	1995 Protocol for Equipment Leak Emission Estimates and Leak Detection and Repair (LDAR) Program
HVGO-Grease	13.4	
Propane REFR-Grease	7.82	
Raffinate-Grease	13.4	
White-Grease	13.4	
Total Emissions:	638	

(b) Mass Balance Calculations for the Fugitive VOC Losses from MEK Dewaxing Unit

(i) Material Usage

Material	1997 Usage			1998 Usage		
	gal/yr	gal/day	lbs/yr	gal/yr	gal/day	lbs/yr
MEK	78000	214	538980	138000	378	953580
Toluene	52000	142	359320	75000	205	518250
Totals	130000	356	898300	213000	583	1471830

Methodology:

Material Usage, lbs/yr = Material Usage (gal/yr) x Density (6.91 lb/gal)

(ii) Tank and Vent Losses

Material	1997and 1998 Point Source Losses				
	Tanks			Vents	
	gal/day	gal/yr	lbs/yr	gal/day	gal/yr
MEK	6.16	2248	15534	24.6	8979
Toluene	3.84	1402	9688	15.4	5621
Totals:	10	3650	**25222 (12.6 tons/yr)**	40	14600

Methodology:

Of the total VOC losses from tanks and vents, MEK makes up 61.55% and Toluene makes up 38.35%.

Tank Emissions, lbs/yr = Tank Emissions, gal/day x 365 day/yr x Density, 6.91 lb/gal

Gas Chromatography testing was conducted on the tank to estimate emission losses.

The emission losses from the vents were not included as available emission reduction credits because these emissions were subject to the MACT requirements.

(b) Mass Balance Calculations for the Fugitive VOC Losses from MEK Dewaxing Unit

(i) Material Usage

Material	1997 Usage			1998 Usage		
	gal/yr	gal/day	lbs/yr	gal/yr	gal/day	lbs/yr
MEK	78000	214	538980	138000	378	953580
Toluene	52000	142	359320	75000	205	518250
Totals	130000	356	898300	213000	583	1471830

Methodology:

Material Usage, lbs/yr = Material Usage (gal/yr) x Density (6.91 lb/gal)

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Gas Chromatography testing was conducted on the tank to estimate emission losses.

The emission losses from the vents were not included as available emission reduction credits because these emissions were subject to the MACT requirements.

(b) Mass Balance Calculations for the Fugitive VOC Losses from MEK Dewaxing Unit

(i) Material Usage

Material	1997 Usage			1998 Usage		
	gal/yr	gal/day	lbs/yr	gal/yr	gal/day	lbs/yr
MEK	78000	214	538980	138000	378	953580
Toluene	52000	142	359320	75000	205	518250
Totals	130000	356	898300	213000	583	1471830

Methodology:

Material Usage, lbs/yr = Material Usage (gal/yr) x Density (6.91 lb/gal)

(ii) Tank and Vent Losses

Material	1997and 1998 Point Source Losses				
	Tanks			Vents	
	gal/day	gal/yr	lbs/yr	gal/day	gal/yr
MEK	6.16	2248	15534	24.6	8979
Toluene	3.84	1402	9688	15.4	5621
Totals:	10	3650	**25222 (12.6 tons/yr)**	40	14600

Methodology:

Of the total VOC losses from tanks and vents, MEK makes up 61.55% and Toluene makes up 38.35%.

Tank Emissions, lbs/yr = Tank Emissions, gal/day x 365 day/yr x Density, 6.91 lb/gal

Gas Chromatography testing was conducted on the tank to estimate emission losses.

The emission losses from the vents were not included as available emission reduction credits because these emissions were subject to the MACT requirements.

Indiana Department of Environmental Management
Office of Air Management

Technical Support Document (TSD) for New Construction and Operation

Source Background and Description

Source Name:	Whiting Clean Energy, Inc.
Source Location:	2155 Standard Avenue, Whiting, Indiana 46394
County:	Lake
Construction Permit No.:	CP-089-11194-00449
SIC Code:	4911
Permit Reviewer:	Michele M. Williams

This new source for Whiting Clean Energy, Inc. (Whiting) relates to the construction and operation of an industrial steam and electric power cogeneration plant consisting of the following equipment:

(a) Two Combustion Turbines:

Make/Model:	General Electric Frame 7FA (Model 7241)
Heat Input Capacity:	1,735 MMBtu per hour (HHV) @ ISO conditions, each
Electric Generating Capacity:	166 MWe @ ISO conditions, each
Fuel Source:	Natural Gas
Control Technology:	Dry Low-NOx Burners
Stack ID:	CT 1 exhausts through HRSG 1 to Stack 1 CT 2 exhausts through HRSG 2 to Stack 2

(b) Two Supplementary Heat Recovery Steam Generators with Two Duct Burners:

Steam Generating Capacity:	1300 psig
Duct Burner Heat Input Capacity:	821 MMBtu per hour (HHV), each
Fuel Source:	Natural Gas
Control Technology:	Selective Catalytic Reduction (SCR) System for NOx Control
Steam Production Capacity:	580,000 pounds per hour, each, without duct burners1,188,000 pounds per hour, each, with duct burners

(c) One Condensing Steam Turbine Generator:

Electric Generating Capacity:	213 MWe @ 1,600,000 pounds per hour steam

(d) Induced Draft Cooling Tower:

System Technology:	5 cycle, 10 cell, induced draft cooling tower
Water Circulation Rate:	160,000 gallons per minute non-contact cooling water
Control Technology:	Drift Eliminator for PM Control

Source Definition

Pursuant to 326 IAC 2-7-2(a)(1), all of the following criteria must be met to consider two plants (Whiting and BP Amoco - Whiting Refinery (Amoco)) as a single major source:

(a) The two plants must be located on one or more contiguous or adjacent properties;

(b) The two plants must be under the same common control; and

(c) The two plants must belong to the same major industrial grouping (same two digit code).

Whiting, a wholly owned subsidiary of Primary Energy, Inc., is proposing to construct and operate the cogeneration facility on the Amoco plant property located in Whiting, Indiana. The primary purpose of the cogeneration facility is to generate electricity. The electricity produced by the steam turbine generator will be sold to the utility distribution grid to meet power demands in Northern Indiana. The steam exhausting from the steam turbine generator will either be recovered by the heat recovery steam generator to produce additional electricity or be used internally at the Amoco refinery for production purposes. Because the primary purpose of the project is to produce electricity for sale, the Whiting facility is considered a separate source from Amoco.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (scfm @ 32 ^{0}F)	Temperature (^{0}F)
Stack 1*	Combustion Turbine 1	140	19	731,774	178
Stack 2*	Combustion Turbine 2	140	19	731,774	178
Volume Source	Cooling Tower (10 cells)	51	20 per cell	337,244 per cell	90

* The information above represents the typical operation of the combustion turbines only. When the duct burners located in the heat recovery steam generators associated with the combustion turbines are operated, the flow rate of each stack increases to 745,402 scfm.

Recommendation

The staff recommends to the Commissioner that the construction and operation be approved. Information used in this review was derived from the application which was received on July 22, 1999 and supporting information received from August 5, 1999 to March 27, 2000.

Emissions Calculations

The emission calculations for the criteria pollutants and hazardous air pollutants (HAPs) are provided in Appendix A. Criteria pollutant emission rates from the turbines are based on General Electric vendor data or Draft EPA AP-42 (5/98) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation) utilizing 100 percent natural gas. Criteria pollutant emission rates from the duct burners are based on vendor data or EPA AP-42 (3/98) emission factors from Chapter 1.4 (Natural Gas Combustion from Boilers) utilizing 100 percent natural gas. It should be noted that the emission factors, heat input and heat content values are based on the higher heating value (HHV). The HHV includes the energy released by condensing the water formed in the combustion reaction.

The HAP emission rates from the turbines are based on Draft EPA AP-42 (5/98) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation) or the California Air Toxics Emission Factor Database (CATEF), version 1.2, June 1998. The HAP emission rates from the duct burners are based on EPA AP-42 emission factors from Chapter 1.4 (Natural Gas Combustion from Boilers).

The particulate emission rates from the cooling tower were also calculated using the cooling tower water circulation rate and a drift loss emission factor provided by the mist eliminator vendor. The calculation equation is from EPA AP-42, Chapter 13.4.

Total Potential to Emit Emissions

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit (PTE) is defined as "the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA."

The following table reflects the PTE before controls of the regulated pollutants from the proposed new source. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Pollutant	PTE (tons/year)	Permit Threshold Levels (tons/year)
PM	113	25
PM-10	113	25
SO_2	13.3	25
VOC	103	25
CO	818	100
NO_x	1083	25
Lead	0.014	5
Single HAP	16.6	10
Combined HAPs	22.3	25

As shown in the above table, the PTE of at least one listed pollutant exceeds its permit threshold level. Therefore, pursuant to 326 IAC 2-5.1-3, a construction permit is required.

County Attainment Status

(a) Volatile organic compounds (VOC) and oxides of nitrogen (NOx) are precursors for the formation of ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to the ozone standards. Lake County has been designated as severe nonattainment for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3.

(b) Lake County has been classified as nonattainment for PM10 and SO2. Therefore, these emissions were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3.

(c) Lake County has been classified as attainment or unclassifiable for PM, NO_2, and CO. Therefore, these emissions were reviewed pursuant to the requirements for PSD, 326 IAC 2-2 and 40 CFR 52.21.

Source Status

The following table compares the emissions after controls (based on 8,760 hours of operation per year at rated capacity unless otherwise limited) to the major source threshold levels to determine the level of review:

Pollutant	Emissions (tons/yr)	Major Source Threshold Level (tons/yr)	Program
PM	90.0	25*	326 IAC 2-2 - PSD + One of 28 Listed Categories
PM10	90.0	100	326 IAC 2-3 - Emission Offset
SO_2	11.4	100	326 IAC 2-3 - Emission Offset
VOC	69.5	25	326 IAC 2-3 - Emission Offset
CO	571	100	326 IAC 2-2 - PSD + One of 28 Listed Categories
NO_x	262	25 (NO_x) 40 (NO_2)*	326 IAC 2-3 - Emission Offset 326 IAC 2-2 - PSD + One of 28 Listed Categories
Asbestos	n/a	0.007*	326 IAC 2-2 - PSD + One of 28 Listed Categories
Beryllium	n/a	0.0004*	326 IAC 2-2 - PSD + One of 28 Listed Categories
Mercury	n/a	0.1*	326 IAC 2-2 - PSD + One of 28 Listed Categories
Vinyl Chloride	n/a	1*	326 IAC 2-2 - PSD + One of 28 Listed Categories
Fluorides	n/a	3*	326 IAC 2-2 - PSD + One of 28 Listed Categories
H2SO4	1.37	7*	326 IAC 2-2 - PSD + One of 28 Listed Categories
H2S	n/a	10*	326 IAC 2-2 - PSD + One of 28 Listed Categories
Total Reduced Sulfur	n/a	10*	326 IAC 2-2 - PSD + One of 28 Listed Categories
Reduced Sulfur Cmpds	n/a	10*	326 IAC 2-2 - PSD + One of 28 Listed Categories

* These threshold levels are the "significant threshold levels". The PSD program states that if any one attainment pollutant exceeds the PSD major source threshold level, then PSD review is required for all other attainment pollutants exceeding the significant threshold levels. The significant threshold levels are lower than the major source threshold levels.

(a) The NOx emissions from the combustion turbine and duct burner will be controlled by a selective catalytic reduction (SCR) system. The duct burner systems have also been limited to burning no more than a fuel equivalent of 5000 hours per year of duct firing at full rate.

(b) Pursuant to the PSD program, the proposed cogeneration plant is classified as a "fossil fuel-fired steam electric plant of more than 250 MMBtu per hour" and therefore is one of the 28 listed categories. The listed categories have a lower major source threshold level of 100 tons per year. The proposed cogeneration plant is a major stationary PSD source because at least one regulated attainment pollutant is emitted above its associated major source threshold level. The proposed source is subject to PSD review for those attainment pollutants which exceed the threshold levels indicated in the above table (PM, CO, and NO_2).

(c) Pursuant to the nonattainment program, the proposed plant is a major stationary source for ozone (NOx and VOC) because the emissions exceed the major source threshold level. According to the nonattainment program, the proposed source is a major stationary source for each nonattainment pollutant that exceeds the major source threshold level. Therefore, the proposed source is not a major stationary source for PM10 or SO2 because neither nonattainment pollutant exceeds its major source threshold level. Therefore, the proposed source is subject to emission offset review only for ozone (NOx and VOC).

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)
This new source is subject to the Part 70 Permit requirements because the PTE of at least one of the criteria pollutant is greater than or equal to 100 tons per year. Therefore, the new source is required to apply for a Part 70 (Title V) operating permit within twelve (12) months after this source becomes subject to Title V.

State and Federal Rule Applicability

326 IAC 1-5-2 and 326 IAC 1-5-3 (Emergency Reduction Plans)
Pursuant to 326 IAC 1-5-2 (Submission of Emergency Reduction Plan):

(a) The Permittee shall prepare a written emergency reduction plan (ERP) consistent with safe operating procedures.

(b) The ERP shall be submitted for approval to the IDEM, OAM Compliance Branch.

(c) If the ERP is disapproved by IDEM, OAM, the Permittee shall have an additional 30 days to resolve the differences and submit an approvable ERP. If after this time the Permittee does not submit an approvable ERP, then IDEM, OAM shall supply such a plan.

(d) The ERP shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) The ERP shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

Pursuant to 326 IAC 1-5-3 (Implementation of ERP), the Permittee shall immediately put into effect the actions stipulated in the approved ERP upon direct notification by OAM that a specific air pollution episode level is in effect.

326 IAC 1-6-3 (Preventive Maintenance Plans)
Pursuant to 326 IAC 1-6-3 (Preventive Maintenance Plans):

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within sixty (60) days upon commercial operation. The PMPs shall include the following information:

 (1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission units;

 (2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

 (3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the PMPs as necessary to ensure that lack of proper maintenance does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMPs shall be submitted to OAM upon request and shall be subject to review and approval by OAM.

326 IAC 2-1-3.4 (New Source Toxic Control)
The New Source Toxics Control rule requires any new or reconstructed major source of hazardous air pollutants (HAPs) for which there is no applicable NESHAP to implement maximum achievable control technology (MACT), determined on a case-by-case basis, when the potential to emit is greater than 10 tons per year of any single HAP or 25 tons per year of any combination of HAP. Indiana presently requests applicants to provide information on emissions of the 187 hazardous air pollutants (listed in the OAM Construction Permit Application, Form Y) set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industries.

The worst case emissions from a single HAP is above the major source threshold level (hexane = 11.1 tons per year with federally enforceable limits). Therefore, this HAP is subject to MACT review. Because hexane is a VOC, MACT shall be good combustion practices. This operating practice is consistent with the VOC BACT review. The combined HAP emissions are less than the major source threshold level and therefore MACT does not apply.

326 IAC 2-2 and 40 CFR 52.21 (Prevention of Significant Deterioration Requirements)
The proposed cogeneration plant is subject to the PSD rules for CO, NO_2 and PM because these attainment pollutants exceed the PSD significant threshold levels reported in 326 IAC 2-2-1. Therefore, the PSD provisions require that this major source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS) and PSD air quality increments, and to implement the best available control technology (BACT) on the source emissions.

The *Air Quality Analysis Report*, included in Appendix B, was conducted to demonstrate that this major source does not violate the National Ambient Air Quality Standards (NAAQS) and does not exceed the incremental consumption above 80 percent of the PSD increment for any pollutant.

The *BACT/LAER Analysis Report*, included in Appendix C, was conducted for the major source PSD pollutants for each process on a case-by-case basis by reviewing similar process controls and new available technologies. The BACT determination is based on the cost per ton of pollutant removed, energy requirements, and environmental impacts. The following BACT emission limitations apply to the proposed plant:

Facility	CO BACT		NO_2 BACT		PM BACT	
	Control	Limit	Control	Limit	Control	Limit
Comb Turbines	Combustion Design	0.016 lb/MMBtu	DLN + SCR	3.0 ppmvd @ 15% O_2, based on a 3-hr rolling average	n/a	0.0045 lb/MMBtu
Comb Turbines + Duct Burners	Combustion Design	0.037 lb/MMBtu	DLN + SCR	3.0 ppmvd @ 15% O_2, based on a 3-hr rolling average	n/a	0.0045 lb/MMBtu
Cooling Tower	n/a	n/a	n/a	n/a	Mist Eliminator	n/a

326 IAC 2-3 (Emission Offset Requirements)
The proposed cogeneration plant is subject to the requirements of 326 IAC 2-3 (Emission Offset) for ozone (VOC and NOx) because these nonattainment pollutants exceed the emission offset threshold levels reported in 326 IAC 2-3. The proposed source shall comply with the following requirements of 326 IAC 2-3-3(a):

(a) Emissions resulting from the proposed construction or modification shall be offset by a reduction in actual emission of the same pollutant from an existing source or combination of existing sources. The emission offset shall be such that there will be reasonable further progress toward attainment of the applicable ambient air quality standards. The following table represents the amount of offsets required for this project:

	Emissions, tons/year	
	NO_X	VOC
Project Emission Facilities:		
Two Combustion Turbines	161	24.3
Two Duct Burners	101	45.2
Cooling Tower	0	0
Potential to Emit:	262	69.5
Emission Offset Threshold Level (326 IAC 2-3-1(j) and (y)):	25	25
Offset Ratio (326 IAC 2-3-3(a)(5)):	1.3	1.3
Required Offsets:	341	90.4

(b) The applicant shall apply emission limitation devices or techniques to the proposed construction such that the lowest achievable emission rate (LAER) for the applicable pollutant will be achieved. A LAER review is required for ozone and PM_{10} because these nonattainment pollutants are above the emission offset threshold levels. The *BACT/LAER Analysis Report*, included in Appendix C, evaluates LAER for the proposed project. Based on this analysis, LAER is established as follows:

Facility	Ozone LAER	
	Control	Limit
Combustion Turbines	NOx: LNB +SCR	3.0 ppmvd NOx @ 15% O_2, based on a 3-hr rolling average
	VOC: Good Combustion	2.8 lb/hr
Combustion Turbines + Duct Burners	NOx: LNB +SCR	3.0 ppmvd NOx @ 15% O_2, based on a 3-hr rolling average
	VOC: Good Combustion	11.8 lb/hr
Cooling Tower	N/A	N/A

Based on the BACT/LAER Analysis report included in Appendix C relating to the NOx emission limit, the OAM has determined that the appropriate emission limit for the proposed Whiting Clean Energy project is 3.0 ppm based on a 3-hr rolling average. Compliance with the 3.0 ppm NOx limit has been verified by continuous monitoring data over a representative time period. There were recently three permits issued to similar sources with a 2.0 ppm emission limit. However, compliance with this emission limit has not been verified. In addition, past data does not support that this limit is achievable on a continuous basis.

(b) The required emission reduction credits are being obtained from the following sources:

Source	Source Air Permit ID	Facility	Emissions, tons/year	
			NO_X	VOC
BP Amoco - Whiting	089-00003	Lubes Unit		X
Ispat Inland, Inc.	089-00316	76" Hot Strip Mill	X	

This information has been included as a condition of the proposed construction permit to make the emission reduction credits federally enforceable.

(c) Pursuant to 326 IAC 2-3-3(a)(3), the applicant shall either demonstrate that all existing major sources owned or operated by the applicant in the state of Indiana are in compliance with all applicable emission limitations and standards contained in the Clean Air Act and 326 IAC, or demonstrate that they are in compliance with a federally enforceable compliance schedule requiring compliance as expeditiously as practicable.

Whiting is a subsidiary of NiSource. The following facilities are all of the existing major sources, as defined in 326 IAC 2-1.1-1, owned and operated by subsidiaries of NiSource in the State of Indiana:

1. Dean H. Mitchell Generating Station
2. Bailey Generating Station
3. Michigan City Generating Station
4. R.M. Schahfer Generating Station
5. Cokenergy, LLC
6. Portside, LLC

NiSource submitted a letter on March 21, 2000 stating that all of these facilities are in compliance with all applicable emission limitations and standards pursuant to the Clean Air Act and Title 326 of the Indiana Administrative Code.

(d) The proposed plant shall demonstrate that the source will meet all applicable requirements of 326 IAC, 40 CFR 60 (New Source Performance Standards), and 40 CFR 61 (National Emission Standards for Hazardous Air Pollutants). Based on the information contained in the application, the proposed facility is in compliance with all applicable requirements.

(e) The applicant shall submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source which demonstrates the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.

The Whiting project is located in this county to meet the increased demand for power. To maximize the resources realized from a cogeneration production unit, it makes sense to locate on or near an industrial plant that would be able to utilize the steam. The Whiting project is located at the BP Amoco Whiting Refinery, where most of the steam produced by the project will be consumed. Because steam is economically transportable only over short distances, other locations are infeasible for this project. The project is sized to meet the BP Amoco steam requirements when both combustion turbines are operating at base load. The project uses natural gas combustion using a combined cycle state-of-the-art technology. This technology is the lowest emitting fossil fuel-fired technology currently available on a per unit of generating capacity basis and generates the least amount of waste per unit of steam and electricity produced.

(f) The applicant shall obtain the necessary preconstruction approvals and shall meet all the permit requirements specified in 326 IAC 2-1. Whiting is in compliance with all the preconstruction approvals required by 326 IAC 2-1.

326 IAC 2-6 (Emission Reporting)

The proposed cogeneration plant is subject to 326 IAC 2-6 (Emission Reporting) because at least one listed pollutant exceeds its emission threshold level. Because the proposed source is located in Lake County, this rule applies when the NOx or VOC PTE exceeds 10 tons per year. This rule also applies to sources when the CO, PM10, or SO2 PTE exceeds 100 tons per year or when the lead PTE exceeds 5 tons per year.

Pursuant to 326 IAC 2-6-3(a), the owner or operator of the proposed source must annually submit an emission statement. The annual statement must be received by April 15 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

326 IAC 3-5 (Continuous Monitoring of Emissions)

The proposed cogeneration plant is subject to 326 IAC 3-5 (Continuous Monitoring of Emissions) because the unit is a fossil fuel-fired steam generator with a heat input capacity greater than 100 MMBtu per hour as defined in 326 IAC 3-5-1(b)(2).

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A)(i), an opacity monitor is not required because only gaseous fuel is combusted. The only fuel to be combusted in the proposed turbine is natural gas.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(B), an SO2 continuous emission monitor (CEM) is not required because each steam generating unit is not equipped with an SO2 control and 40 CFR 60 Subpart Db does not require and SO2 monitor because only gaseous fuel (natural gas) is combusted.

(c) Pursuant to 326 IAC 3-5-1(c)(2)(C), a NOx CEM is required because each steam generating unit is equipped with low-NOx burners. The NOx CEM shall determine compliance with 326 IAC 12.

(d) Pursuant to 326 IAC 3-5-1(c)(2)(D), the percent O2 if measurements of O2 in the flue gas are required to convert either SO2 or NOx CEM data, or both, to units of the emission limitation for the particular facility.

(e) For NOx and O2, the Permittee shall install, calibrate, certify, operate and maintain a continuous monitoring system for each steam generating unit in accordance with 326 IAC 3-5:

    (1) The CEM shall measure NOx and O2 emissions rates in pounds per hour and parts per million (ppmvd). The use of CEMs to measure and record the NOx and O2 hourly limits, is sufficient to demonstrate compliance. The source shall maintain records of the parts per million and pounds per hour.

    (2) The Permittee shall submit to OAM, within 90 days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

    (3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7. The source shall also be required to maintain records of the amount of natural gas combusted per turbine on a monthly basis and the heat input.

326 IAC 5-1 (Opacity Limitations)
The proposed cogeneration plant is subject to 326 IAC 5-1-1 (Opacity Limitations) because opacity, not including condensed water vapor, is emitted from the facilities at the source. Pursuant to 326 IAC 5-1-1(c), sources located in Lake County are subject to 326 IAC 5-1-2(2) which limits the opacity to an average of 20 percent in any one 6 minute averaging period and 60 percent for more than a cumulative total of 15 minutes (60 readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen 1 minute nonoverlapping integrated averages for a continuous opacity monitor) in a 6 hour period.

326 IAC 6-1 (Nonattainment Area Particulate Limitations)
The proposed industrial steam and electric power cogeneration plant is subject to 326 IAC 6-1 (Nonattainment Area Particulate Limitations) because the proposed Whiting facility is located in Lake County, a nonattainment area for particulate matter as listed in 326 IAC 6-1-7, and has the potential to emit 100 tons or more of particulate matter per year.

The proposed duct burners are subject to the Afuel combustion steam generator@ category requirements (326 IAC 6-1-2(b)(5)) which limit the particulate matter emissions to no more than 0.01 grains per dry standard cubic feet (dscf).

The proposed combustion turbines are subject to the general requirements (326 IAC 6-1-2(a)) which limit the particulate matter emissions to no more than 0.03 grains per dry standard cubic feet (dscf).

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)
The proposed cogeneration plant is not subject to the requirements of 326 IAC 6-2 because the proposed plant is subject to the requirements of 326 IAC 12 (New Source Performance Standards). Pursuant to the applicability requirements (326 IAC 6-2-1(d) and (e)), if any limitation established by this rule is inconsistent with applicable limitations contained in 326 IAC 6-1 (Nonattainment Particulate Emission Limitations) or 326 IAC 12 (New Source Performance Standards), then the limitations contained in 326 IAC 6-1 or 326 IAC 12 prevail.

326 IAC 6-4 (Fugitive Dust Emission Limitations)
The proposed cogeneration plant is subject to the requirements of 326 IAC 6-4 because this rule applies to all sources of fugitive dust. Pursuant to the applicability requirements (326 IAC 6-2-1(d) and (e)), “fugitive dust” means the generation of particulate matter to the extent that some portion of the material escapes beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located. The source shall be considered in violation of this rule if any of the criteria presented in 326 IAC 6-4-2 are violated.

326 IAC 6-5 (Fugitive Particulate Matter Emissions Limitations)
The proposed cogeneration plant is subject to the requirements of 326 IAC 6-5 because the proposed new plant must obtain a permit pursuant to 326 IAC 2. However, the OAM shall exempt the source from the fugitive control plan pursuant to 326 IAC 6-5-3(b) because the proposed plant will not have material delivery or handling systems that would generate fugitive emissions and all the roads and parking areas will be paved.

326 IAC 7-1 (Sulfur Dioxide Emission Limitations)
The proposed power plant is subject to the requirements of 326 IAC 7-1 because the plant is a fuel combustion facility and the SO2 PTE is greater than 25 tons per year. Pursuant to 326 IAC 7-1.1-2, there are no specific emission limitations for the combustion of natural gas. Pursuant to 326 IAC 7-2-1, the

Permittee shall submit natural gas reports of calendar month average sulfur content, heat content, natural gas fuel consumption, and sulfur dioxide emission rate in pounds per million Btu upon request of the OAM.

326 IAC 8-1-6 (Volatile Organic Compound State BACT Requirements)
The proposed cogeneration plant is subject to the requirements of 326 IAC 8-1-6 (State BACT Requirements) because the VOC PTE exceeds 25 tons per year. The VOC emissions from the proposed plant are also subject to the requirements of 326 IAC 2-2 (Federal BACT Requirements). The VOC BACT evaluation is included in Appendix B. BACT of the combustion sources shall be the implementation of good combustion practices to minimize VOC emissions.

326 IAC 8 (Volatile Organic Compound Requirements)
The proposed cogeneration plant is not subject to any other state VOC requirements because there is not a source specific RACT for the proposed operation.

326 IAC 9 (Carbon Monoxide Emission Limitations)
The proposed plant is subject to 326 IAC 9 (Carbon Monoxide Emission Limitations) because it is a stationary source which emits CO emissions and commenced operation after March 21, 1972. However, there are no specific emission limitations required by this rule because the source is not an operation listed under 326 IAC 9-1-2.

326 IAC 10 (Nitrogen Oxide Emission Limitations)
The proposed plant is not subject to the requirements of 326 IAC 10 (Nitrogen Oxide Emission Limitations) because the proposed plant is not located in Clark County or Floyd County.

326 IAC 12 and 40 CFR 60 Subpart Da (NSPS for Electric Utility Steam Generating Units)
The proposed plant is subject to the New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units (40 CFR 60 Subpart Da) because it is an electric utility steam generating facility that will be constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale.

According to 40 CFR 60.40a(b) (Applicability), the two duct burners (821 MMBtu per hour, each), which constitute a portion of the electric utility steam generating unit, are subject to the requirements of this rule because they are capable of combusting more than 250 MMBtu per hour heat input of fossil fuel. However, the two gas combustion turbines are not subject to this subpart as stated in 40 CFR 60.40a(b) because the turbines are subject to the requirements of 40 CFR 60 Subpart GG.

(a) Particulate matter emissions from each natural gas-fired duct burner shall not exceed 0.03 pounds per MMBtu heat input pursuant to 40 CFR 60.42a(a)(1). Opacity shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent pursuant to 40 CFR 60.42a(b).

(b) Pursuant to 40 CFR 60.43a(b)(2) and 40 CFR 60.43a(g) (Sulfur Dioxide Standards), sulfur dioxide emissions from each natural gas-fired duct burner shall not exceed 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.20 pounds per MMBtu heat input, based on a 30-day rolling average.

(c) Pursuant to 40 CFR 60.44a(d)(2) (Nitrogen Oxide Standards), nitrogen oxide emissions from each natural gas-fired duct burner shall not exceed 1.6 pounds/MW-hr gross energy output on a 30-day rolling average.

(d) Pursuant to 40 CFR 60.46a (Compliance Provisions), the natural gas-fired duct burners are subject to the following requirements:

(1) The particulate matter emission standards and nitrogen oxide standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide standards apply at all times except during periods of startup or shutdown;

(2) After the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rate for 30 successive burner operating days. A separate performance test is completed at the end of each burner operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides; and

(3) For the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rates for the first 30 successive burner operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first burner operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the facility.

(e) Pursuant to 40 CFR 60.47a(a) and (b) (Emission Monitoring for Opacity and Sulfur Dioxide), the duct burners are not subject to the opacity and sulfur dioxide emission monitoring requirements because only natural gas fuel is combusted.

(f) Pursuant to 40 CFR 60.47a(c) (Emission Monitoring for Nitrogen Oxide), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(g) Pursuant to 40 CFR 60.47(d) (Emission Monitoring for Oxygen or Carbon Dioxide), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored.

(h) Pursuant to 40 CFR 60.48a (Compliance Determination Procedures), the Permittee shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures specified in this section. The Permittee shall determine compliance with the NOx standard as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NOx.

(2) The continuous monitoring system shall be used to determine the concentrations of NOx and O2.

(i) Pursuant to 40 CFR 60.49a (Reporting Requirements), the Permittee is subject to the following reporting requirements:

(1) NOx performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the

Administrator.

(2) Information required by 40 CFR 60.49a(b) from the NOx CEM for each 24-hour period.

(3) Information required by 40 CFR 60.49a(c) when the minimum quantity of emission data is not obtained for any 30 successive burner operating days.

(4) For any periods for which nitrogen oxides emissions data are not available, the Permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(5) Pursuant to 40 CFR 60.49a(g), the Permittee shall submit a signed statement indicating whether:

(A) The required CEM calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(B) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(C) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(D) Compliance with the standards has or has not been achieved during the reporting period.

(6) For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are submitted to the Administrator each calendar quarter.

(7) The Permittee shall submit the written reports to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

<u>40 CFR 60 Subpart Db (New Source Performance Standards for Industrial Steam Generating Units)</u>
The proposed cogeneration plant is not subject to the New Source Performance Standard (NSPS) for Industrial Steam Generating Units (40 CFR 60 Subpart Db) because the proposed plant is subject to the requirements of 40 CFR 60 Subpart Da. According to 40 CFR 60.40b(e) (Applicability Requirements), steam generating units meeting the applicability requirements of 40 CFR 60 Subpart Da are not subject to this subpart (40 CFR 60 Subpart Db).

<u>326 IAC 12 and 40 CFR 60 Subpart GG (NSPS for Stationary Gas Turbines)</u>
The two natural gas-fired combustion turbines are subject to the New Source Performance Standard (NSPS) for Stationary Gas Turbines (40 CFR 60 Subpart GG) because the heat input at peak load of each

combustion turbine (1,735 MMBtu per hour) equals or exceeds 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

(a) Pursuant to 40 CFR 60.332(b) (Nitrogen Oxide Standards), the nitrogen oxides emissions from each natural gas-fired combustion turbine shall comply with the provisions of 40 CFR 60.332(a)(1) as follows:

$$STD = 0.0075 \times ((14.4)/Y) + F$$

where:

STD = Allowable NOx percent by volume @ 15% O_2
Y = Heat Rate Capacity
F = NOx emission allowance for fuel-bound nitrogen

(b) Pursuant to 40 CFR 60.333 (Sulfur Dioxide Standards), sulfur dioxide emissions from each natural gas-fired combustion turbine shall not exceed 0.015 percent by volume at 15 percent oxygen and on a dry basis. In addition, natural gas fuel shall not exceed 0.8 percent sulfur by weight.

(c) Pursuant to 40 CFR 60.334(b) (Monitoring of Operations), the Permittee shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine on a daily basis, or submit an alternative plan to the OAM for approval. The Permittee may develop schedules for determination of these values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).

(d) Pursuant to 40 CFR 60.334(c)(1) (NOx Monitoring), the Permittee must submit a report of periods of excess emissions as determined by any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than te maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

(e) Pursuant to 40 CFR 60.334(c)(2) (SO2 Monitoring), the Permittee must submit a report of periods of excess emissions as determined by any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

<u>326 IAC 20 and 40 CFR 63 (National Emissions Standards for Hazardous Air Pollutants)</u>
There are presently no proposed or final National Emissions Standards for Hazardous Air Pollutant (NESHAP) regulations for electric utility steam generating units.

<u>326 IAC 21 and 40 CFR 72 (Acid Rain Program)</u>
The proposed source is subject to the requirements of the Acid Rain Program because the cogeneration plant supplies equal to or more than one-third its potential electrical output capacity on an annual basis to any utility power distribution system for sale. The owner or operator must obtain an Acid Rain Permit prior to operation of the source. The Acid Rain application for Whiting (Acid Rain Permit No. AR-089-11912-00449) was received on February 21, 2000.

Conclusion

The construction of an cogeneration plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-089-11194-00449.**

Appendix A: Emission Calculations

Company Name: Whiting Clean Energy, Inc.
Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394
CP: 089-11194
Plt ID: 089-00449
Reviewer: Michele M. Williams

A. Emission Factors for Combustion Turbines and Duct Burners

Pollutant	Fuel	Emission Factor	Basis
Combustion Turbines:			
SO_2	Natural Gas	0.0006 lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf
NOx	Natural Gas	0.0334 lb/MMBtu	GE Data Sheet dated THIBAUBE 3/4/99; 58 lb NO_2/hr @ BASE 59^o
VOC	Natural Gas	0.0016 lb/MMBtu	GE Data Sheet dated THIBAUBE 3/4/99; 2.8 lb VOC/hr @ BASE 59^o
PM_{10}	Natural Gas	0.0045 lb/MMBtu	Stack Test Information of Similar Sized Combined Cycle facility in Pasadena, TX
TSP	Natural Gas	0.0045 lb/MMBtu	Assume that PM = PM10
H_2SO_4	Natural Gas	0.00008 lb/MMBtu	0.08 fraction of SO2 * (134 $MW_{H2SO4 + 2H2O}$ / 64 MW_{SO2})
CO	Natural Gas	0.0161 lb/MMBtu	GE Data Sheet dated THIBAUBE 3/4/99; 28 lb CO/hr @ BASE 59^o
Pb	Natural Gas	4.90E-07 lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf
Duct Burners:			
SO_2	Natural Gas	0.0006 lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf
NOx	Natural Gas	0.08 lb/MMBtu	AAL Borg Letter dated 11/22/99 -- 65.7 lb/hr
VOC	Natural Gas	0.011 lb/MMBtu	Forney's Letter dated 11/22/99 -- 0.011 lb/MMBtu HHV nonmethane/ethane VOC
PM_{10}	Natural Gas	0.0045 lb/MMBtu	Stack Test Information of Similar Sized Combined Cycle facility in Pasadena, TX
TSP	Natural Gas	0.0045 lb/MMBtu	Assume that PM = PM10
H_2SO_4	Natural Gas	3.66E-05 lb/MMBtu	AP-42 Table 1.3-1 (5.7S/157S) ratio of SO_2 * (98 MW_{H2SO4} / 80 MW_{SO3})
CO	Natural Gas	0.08 lb/MMBtu	AAL Borg Letter dated 11/22/99 -- 65.7 lb/hr
Pb	Natural Gas	4.90E-07 lb/MMBtu	AP-42 Table 1.4-2 lb/MMscf value divided by natural gas HHV of 1020 Btu/scf

B. Emissions Summary

Pollutant	PTE, Before Controls (tons/year)				PTE, After Controls or Enforceable Limits (tons/year)			
	Two Combustion Turbines	Two Duct Burners	Cooling Tower	Totals	Two Combustion Turbines	Two Duct Burners	Cooling Tower	Totals
NOx	508	575	--	1083	161	101	--	262
VOC	24.3	79.1	--	103	24.3	45.2	--	69.5
SO2	8.97	4.32	--	13.3	8.97	2.46	--	11.4
PM10	68.4	32.4	12.3	113	68.4	9.25	12.3	90
TSP	68.4	32.4	12.3	113	68.4	9.25	12.3	90
H2SO4	1.22	0.26	--	1.48	1.22	0.26	--	1.37
CO	243	575	--	818			--	571
Pb	0.01	0.0036	--	0.014	0.01	0.0021	--	0.012
Single HAP	3.86	12.7	--	16.6	3.86	7.24	--	11.1
Combined HAP	8.94	13.3	--	22.3	8.94	7.60	--	16.6

C. Combustion Turbine and Duct Burner Potential-To-Emit Calculations for Criteria Pollutants - Before Controls or Federally Enforceable Limits

Pollutant	Calculations														
GE PG7241(FA) Combustion Turbines:															
					lbs/hr						tons/yr/CT				tons/yr
NOx	1735 MMBtu/hr	*	0.0334 lb/MMBtu	=	57.9	*	8760 hrs/yr	/	2000 lbs/ton	=	253.8	*	2 CTs	=	508
VOC	1735 MMBtu/hr	*	0.0016 lb/MMBtu	=	2.78	*	8760 hrs/yr	/	2000 lbs/ton	=	12.2	*	2 CTs	=	24.3
SO_2	1735 MMBtu/hr	*	0.00059 lb/MMBtu	=	1.02	*	8760 hrs/yr	/	2000 lbs/ton	=	4.48	*	2 CTs	=	8.97
PM_{10}	1735 MMBtu/hr	*	0.0045 lb/MMBtu	=	7.8	*	8760 hrs/yr	/	2000 lbs/ton	=	34.2	*	2 CTs	=	68.4
TSP	1735 MMBtu/hr	*	0.0045 lb/MMBtu	=	7.8	*	8760 hrs/yr	/	2000 lbs/ton	=	34.2	*	2 CTs	=	68.4
H_2SO_4	1735 MMBtu/hr	*	0.00008 lb/MMBtu	=	0.139	*	8760 hrs/yr	/	2000 lbs/ton	=	0.61	*	2 CTs	=	1.22
CO	1735 MMBtu/hr	*	0.016 lb/MMBtu	=	27.8	*	8760 hrs/yr	/	2000 lbs/ton	=	122	*	2 CTs	=	243
Pb	1735 MMBtu/hr	*	5E-07 lb/MMBtu	=	0.0009	*	8760 hrs/yr	/	2000 lbs/ton	=	0.0038	*	2 CTs	=	0.01
COEN Duct Burners:															
					lbs/hr						tons/yr/DB				tons/yr
NOx	821 MMBtu/hr	*	0.08 lb/MMBtu	=	65.7	*	8760 hrs/yr	/	2000 lbs/ton	=	288	*	2 CTs	=	575
VOC	821 MMBtu/hr	*	0.011 lb/MMBtu	=	9.0	*	8760 hrs/yr	/	2000 lbs/ton	=	39.6	*	2 CTs	=	79.1
SO_2	821 MMBtu/hr	*	0.0006 lb/MMBtu	=	0.49	*	8760 hrs/yr	/	2000 lbs/ton	=	2.16	*	2 CTs	=	4.32
PM_{10}	821 MMBtu/hr	*	0.0045 lb/MMBtu	=	3.69	*	8760 hrs/yr	/	2000 lbs/ton	=	16.2	*	2 CTs	=	32.4
TSP	821 MMBtu/hr	*	0.0045 lb/MMBtu	=	3.69	*	8760 hrs/yr	/	2000 lbs/ton	=	16.2	*	2 CTs	=	32.4
H_2SO_4	821 MMBtu/hr	*	0.000036 lb/MMBtu	=	0.030	*	8760 hrs/yr	/	2000 lbs/ton	=	0.129	*	2 CTs	=	0.26
CO	821 MMBtu/hr	*	0.08 lb/MMBtu	=	65.7	*	8760 hrs/yr	/	2000 lbs/ton	=	288	*	2 CTs	=	575
Pb	821 MMBtu/hr	*	5E-07 lb/MMBtu	=	0.0004	*	8760 hrs/yr	/	2000 lbs/ton	=	0.0018	*	2 CTs	=	0.0036

D. Combustion Turbine and Duct Burner Potential-To-Emit Calculations for Criteria Pollutants - After Controls or Federally Enforceable Limits

Pollutant	Calculations																	
GE PG7241(FA) Combustion Turbines:								lbs/hr						tons/yr/CT				tons/yr
NOx	1735 MMBtu/hr	*	0.0334 lb/MMBtu	*	0.331	SCR NOx Control Fraction (CT Only)	=	19.2	*	3760 hrs/yr	/	2000 lbs/ton	=	36.1	*	2 CTs	=	72.1
	1735 MMBtu/hr	*	0.0334 lb/MMBtu	*	0.307	SCR NOx Control Fraction (CT Only)[1]	=	17.8	*	5000 hrs/yr	/	2000 lbs/ton	=	44.5	*	2 CTs	=	89.0
VOC	1735 MMBtu/hr	*	0.0016 lb/MMBtu				=	2.78	*	8760 hrs/yr	/	2000 lbs/ton	=	12.2	*	2 CTs	=	24.3
SO_2	1735 MMBtu/hr	*	0.00059 lb/MMBtu				=	1.02	*	8760 hrs/yr	/	2000 lbs/ton	=	4.48	*	2 CTs	=	8.97
PM_{10}	1735 MMBtu/hr	*	0.0045 lb/MMBtu				=	7.81	*	8760 hrs/yr	/	2000 lbs/ton	=	34.2	*	2 CTs	=	68.4
TSP	1735 MMBtu/hr	*	0.0045 lb/MMBtu				=	7.81	*	8760 hrs/yr	/	2000 lbs/ton	=	34.2	*	2 CTs	=	68.4
H_2SO_4	1735 MMBtu/hr	*	0.00008 lb/MMBtu			[1] Due to higher SCR temp during duct firing	=	0.139	*	8760 hrs/yr	/	2000 lbs/ton	=	0.61	*	2 CTs	=	1.22
CO	1735 MMBtu/hr	*	0.016 lb/MMBtu			SCR efficiency is higher than during CT only	=	27.8	*	8760 hrs/yr	/	2000 lbs/ton	=	122	*	2 CTs	=	243
Pb	1735 MMBtu/hr	*	0.0000005 lb/MMBtu				=	0.0009	*	8760 hrs/yr	/	2000 lbs/ton	=	0.0038	*	2 CTs	=	0.01
COEN Duct Burners:								lbs/hr						tons/yr/DB				tons/yr
NOx	821 MMBtu/hr	*	0.08 lb/MMBtu	*	0.307	SCR NOx Control Fraction (CT Only)	=	20.2	*	5000 hrs/yr	/	2000 lbs/ton	=	50.4	*	2 CTs	=	101
VOC	821 MMBtu/hr	*	0.011 lb/MMBtu				=	9.0	*	5000 hrs/yr	/	2000 lbs/ton	=	22.6	*	2 CTs	=	45.2
SO_2	821 MMBtu/hr	*	0.0006 lb/MMBtu				=	0.49	*	5000 hrs/yr	/	2000 lbs/ton	=	1.23	*	2 CTs	=	2.46
PM_{10}	821 MMBtu/hr	*	0.0045 lb/MMBtu				=	3.6945	*	5000 hrs/yr	/	2000 lbs/ton	=	9.2	*	2 CTs	=	18.5
TSP	821 MMBtu/hr	*	0.0045 lb/MMBtu				=	3.6945	*	5000 hrs/yr	/	2000 lbs/ton	=	9.2	*	2 CTs	=	18.5
H_2SO_4	821 MMBtu/hr	*	0.000036 lb/MMBtu				=	0.030	*	5000 hrs/yr	/	2000 lbs/ton	=	0.074	*	2 CTs	=	0.15
CO	821 MMBtu/hr	*	0.08 lb/MMBtu				=	65.68	*	5000 hrs/yr	/	2000 lbs/ton	=	164	*	2 CTs	=	328
Pb	821 MMBtu/hr	*	0.0000005 lb/MMBtu				=	0.00041	*	5000 hrs/yr	/	2000 lbs/ton	=	0.0010	*	2 CTs	=	0.0021

NOTE: The OAM evaluated and approved the emission calculations performed by the company for converting "ppm" BACT emission rates for CO and NOx to "pound/hour" potential emission rates. These calculations have been included at the end of this section.

E. Startup/Shutdown Emissions

There are more combustion pollutant emissions (CO and NOx) generated during startup/shutdown operations than during normal operation.
Therefore, these emissions must be evaluated as part of the potential emissions generated from the source.
The following calculations were performed for the startup/shutdown operations:

Parameter	Value	Reference/Calculations
Number Startup/Shutdown per year	60 startup/shutdown/year	Scheduled Operation
NOx Emissions/Startup/Shutdown	120 lbs/startup/shutdown	GE Vendor Information
CO Emissions/Startup/Shutdown	32 lbs/startup/shutdown	GE Vendor Information
Startup/Shutdown NOx Emissions	3.6 tons/year	
Startup/Shutdown CO Emissions	0.96 tons/year	

F. Combustion Turbine and Duct Burner Potential-To-Emit Calculations for HAPs

HAP	Combustion Turbine (CT)			Duct Burner (DB)				CT + DB		Project Total - 2 CTs + 2 DBs	
	lb/MMscf	lb/hr	ton/yr	lb/MMscf	lb/hr	ton/yr @ 8760hr/yr	ton/yr @ 5000hr/yr	ton/yr before control	ton/yr after control	ton/yr before control	ton/yr after control
Acetaldehyde (1)	0.0686	0.12	0.51	No Data				0.511	0.511	1.02	1.02
Acrolein (1)	0.0237	0.04	0.18	No Data				0.177	0.177	0.353	0.353
Benzene (1)	0.0136	0.02	0.10	0.0021	0.002	0.007	0.004	0.109	0.106	0.217	0.211
1,3 Butadiene (1)	0.000127	0.0002	0.0009	No Data				0.001	0.001	0.002	0.002
Dichlorobenzene (2)	0.0012	0.002	0.009	0.0012	0.001	0.004	0.002	0.013	0.011	0.026	0.023
Ethylbenzene (1)	0.0179	0.030	0.133	No Data				0.133	0.133	0.267	0.267
Formaldehyde (1)	0.11	0.187	0.820	0.075	0.060	0.264	0.151	1.08	0.970	2.17	1.94
Hexane (1)	0.259	0.441	1.93	1.8	1.45	6.35	3.62	8.28	5.552	16.6	11.1
Naphthalene (1)	0.00166	0.003	0.012	0.0006	0.0005	0.002	0.001	0.015	0.014	0.029	0.027
PAHs (1)	0.00066	0.001	0.005	No Data				0.005	0.005	0.010	0.010
Toluene (1)	0.071	0.121	0.529	0.0034	0.003	0.012	0.007	0.541	0.536	1.08	1.07
Xylene (1)	0.0261	0.044	0.194	No Data				0.194	0.194	0.389	0.389
Arsenic (2)	0.0002	0.000	0.001	0.0002	0.0002	0.001	0.0004	0.002	0.002	0.004	0.004
Beryllium (2)	0.000012	2.04E-05	8.94E-05	0.000012	0.00001	0.00004	0.00002	0.0001	0.0001	0.000	0.000
Cadmium (2)	0.0011	0.002	0.008	0.0011	0.001	0.004	0.002	0.012	0.010	0.024	0.021
Chromium (2)	0.0014	0.002	0.010	0.0014	0.001	0.005	0.003	0.015	0.013	0.031	0.026
Lead (2)	0.0005	0.0009	0.004	0.0005	0.0004	0.002	0.001	0.005	0.005	0.011	0.009
Manganese (2)	0.00038	0.0006	0.003	0.00038	0.0003	0.001	0.001	0.004	0.004	0.008	0.007
Mercury (2)	0.00026	0.0004	0.002	0.00026	0.0002	0.001	0.001	0.003	0.002	0.006	0.005
Molybdenum (2)	0.0011	0.002	0.008	0.0011	0.001	0.004	0.002	0.012	0.010	0.024	0.021
Nickel (2)	0.0021	0.004	0.016	0.0021	0.002	0.007	0.004	0.023	0.020	0.046	0.040
Selenium (2)	0.000045	7.65E-05	0.0003	0.000045	0.00004	0.0002	0.0001	0.0005	0.0004	0.001	0.001
Total HAP Emissions:										22.3	16.6

NOTE: (1) California Air Toxic Emission Factors (CATEF) Version 1.2, June 1998
(2) Compilation of Ar Pollutant Emission Factors Jan 1995, Table 1.4-3 and Table 1.4-4

NOTE: The OAM reviewed and accepted the emission factor data presented by the company. According to the company, the CATEF data was used for three reasons. First, the CATEF data contained emission factors for pollutants found in Form Y that AP-42 data did not address: acetaldehyde, acrolein, butadiene, ethylbenzene, polyorganic material, and zylenes. Secondly, CATEF data was used instead of AP-42 data because the CATEF emssion factors were higher than the AP-42 emission factors for benzene, formaldehyde, napthalene, and toluene. Thirdly, the CATEF data was used for hexane instead of AP-42 data because the AP-42 emission factor for hexane is several orders of magnitude greater than the other HAP emission factors and the AP-42 emission factor is not considered representative of anticipated emissions bsed on recent GE turbine emission tests for similar CTs.

G. Cooling Tower Emissions

Parameter	Value	Units	References/Calculations
Flow of Water Through Tower =	160,000	gpm	Cooling Tower Drift Losses
Water, specific gravity @ 60 F =	8.34	lb/gal	
Cooling Water Flow Rate, lb/hr =	80,064,000	lb/hr flow	160,000 gpm * 8.32 lb/gal * 60 min/hr
			AP-42 Guidance, Section 13.4, Wet Cooling Towers
Total Dissolved Solids (TDS) =	3,500	ppmw	per Amoco Corporation
Cooling Water TDS Fraction =	0.0035	lb TDS/lb	3500 ppm / 106 lb/ppm
Drift Losses (% Cooling Water) =	0.001	percent	Vendor Information
Liquid Drift Losses =	801	lb/hr	lb/hr cooling water flow * 0.001%/100
Solids Drift Losses =	2.8	lb/hr	lb/hr liquid drift losses * 0.001 lb/ TDS/lb cooling water flow
PM10/TSP Emissions:	12.3	tpy	

NOTE: The cooling tower emissions are calculated using cooling tower water circulation rate and a drift loss emission factor provided by the mist eliminator vendor. The calculation equation is from AP-42, Section 13.4-3 as follows:

> "…a conservatively high PM-10 emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particules are within the PM-10 size range."

No emission of VOC are expected because the cooling water will not contact equipment in VOC service.

H. Conversion Calculations

The following calculations were performed to determine the pound per hour emission rate of combustion emissions (NOx and CO) from the combustion turbines and duct burners that were guaranteed by a ppm emission rate:

1. Combustion Turbine Input Parameters

ppm = ppmvd @ actual exhaust O2 (dry)
Exhaust Gas (EG) Flowrate (dscf/min) is @ 25^{0}C (68^{0}C)
MW of EG = 28.4
CT Flowrate = 3,471,000 pounds/hr (total or wet) based on GE Data Sheet @ baseload ISO conditions

	EG - Composition Volume %	MW lb/lb-mole	Weight lb/lb-mole EG
AR	0.89	39.95	0.356
N2	74.4	28.01	20.85
O2	12.4	32	3.97
CO2	3.89	44	1.71
H2O	8.42	18.02	1.52

Molar Flowrate = 3,471,000/28.4 = 122,231 lb-mol/hr EG

EG Flowrate (wet @ 0^{0}C) = 122,231 lb-mol/hr x 359 ft^3/lb-mol @ 0^{0}C x hr/60 min
EG Flowrate (wet @ 0^{0}C) = 731,447 ft^3/min

EG Flowrate (dry @ 0^{0}C) = 731,447 x (1 - 0.0842)
EG Flowrate (dry @ 0^{0}C) = 669,859 ft^3/min

EG Flowrate (dry @ 25^{0}C) = 669,859 x ((273 + 25) / 273)
EG Flowrate (dry @ 25^{0}C) = 731,201 ft^3/min

2. NOx Emissions from the Combustion Turbines

NOx Limit = 3.0 ppmvd @ 15% O_2 (must convert to actual O_2)
Actual % O_2 on a wet basis (from GE Data Sheet) = 12.40
Actual % O_2 on a dry basis (from GE Data Sheet) = 13.54

Actual ppm @ Actual % O_2 = 3.0 ppm x ((21 - 13.54) / (21 - 15))
Actual ppm @ Actual % O_2 = 3.73 ppmvd

NOx Emission Rate per Turbine = (3.73 ppm NOx) x (1 lbs NOx/ft^3 / 8.375x10^6 ppm NOx) x (731,201 ft^3/min) x (60 min/hr)
NOx Emission Rate per Turbine = 19.5 lbs/hr

NOx Emission Rate per Turbine = 19.5 lbs/hr x ton/2000 lbs x 8760 hrs/yr
NOx Emission Rate per Turbine = 85.4 tons/yr

3. CO Emissions from the Combustion Turbines

CO Limit = 9.0 ppmvd @ 15% O_2 (must convert to actual O_2)

CO Emission Rate per Turbine = (9 ppm NOx) x (1 lb CO/ft^3 / 1.38x107 ppm CO) x (731,201 ft^3/min) x (60 min/hr)
CO Emission Rate per Turbine = 28.6 lbs/hr

CO Emission Rate per Turbine = 28.6 lbs/hr x ton/2000 lbs x 8760 hrs/yr
CO Emission Rate per Turbine = 125 tons/yr

4. Input Parameters for Combustion Turbines and Duct Burners

Duct Burner Heat In = 821.3 MMBtu/hr
Natural Gas Heat Value = 1020 Btu/ft^3

Molar Flowrate of Duct Burner = (821.3 MMBtu/hr x 10^6 Btu/MMBtu) / (1020 Btu/ft^3 x 385.3 ft^3 @ 25^0C/lb-mole)
Molar Flowrate of Duct Burner = 2089.7 lb-mole NG/hr

If we assume NG is CH4 for purpose of calculation, then the following reaction takes place:

CH_4 + 2 O_2 ---------> CO_2 + 2 H_2O

This says that for every mole of CH_4 we consume, 2 moles of O_2 in the CT exhaust gas and produce 3 moles of product gases. The molar addition to the exhaust flow is therefore 1:1. But, 2 moles of water produced.
Therefore, the following additional flow is added to the combustion turbine exhaust as a result of the duct burner:

Exhaust Flowrate of Duct Burner = 2089.7 lb-mole/hr x hr/60 min x 385.3 ft^3/lb-mole
Exhaust Flowrate of Duct Burner = 13,419 ft^3/min of additional wet exhaust

Because there is 2 moles of H_2O produced: 13,419 ft3/min of additional wet exhaust - 2(13,419 ft3/min of H_2O in exhaust)
Exhaust Flowrate of Duct Burner (dry) = 13,419 - 2(13,419)

Exhaust of CT and DB (dry @ 25^0C) = 731,201 ft^3/min - 13,419 ft^3/min
Exhaust of CT and DB (dry @ 25^0C) = 717,781 ft^3/min

EG from Combustion Turbine (wet) = 122,231 lb-mol/hr
Actual % O_2 on a wet basis (from GE Data Sheet) = 12.40

Molar O_2 Rate = 0.124 x 122,231 lb-mole/hr
Molar O_2 Rate = 15,156.6 lb-mole/hr

DB O_2 Reduction = 2(2089.7 lb-mole NG/hr)
DB O_2 Reduction = 4,179.4 lb-mole /hr

O_2 in EG after DB = 15,156.6 lb-mol O_2/hr - 4,179.4 lb-mol O_2/hr)
O_2 in EG after DB = 10,977.2 lb-mole O_2/hr

EG from Combustion Turbine + Duct Burner = 122,231 lb-mole/hr + 2089.7 lb-mole/hr
EG from Combustion Turbine + Duct Burner = 124,320.7 lb-mole/hr (wet)

Moisture in Combustion Turbine and Duct Burner:

CT Moisture = (122,231 lb-mole/hr) x (0.0842) = 10,291.9 lb-mole/hr
DB Moisture = 2 (2,089.7 lb-mole/hr) = 4,179.4 lb-mole/hr
Total Moisture = (10,291.9 + 4,179.4) lb-mole/hr
Total Moisture = 14,471.3 lb-mole/hr

CT + DB (dry) = (124,320.7 - 14,471.3) lb-mole/hr
CT + DB (dry) = 109,849.4 lb-mole/hr

Actual % O2 (dry) = 10,977.2 / 109,849.4
Actual % O2 (dry) = 9.99%

5. NOx Emissions from the Combustion Turbines and Duct Burners

Actual ppm @ Actual % O_2 = 3.0 ppm x ((21 - 9.99) / (21 - 15))
Actual ppm @ Actual % O_2 = 5.51 ppmvd

NOx Emission Rate per Turbine and Duct Burner = (5.51 ppm NOx) / (1 lb NOx/ft3 / 8.375x10^6 ppm NOx) x (717,731 ft3/min) x (60 min/hr)
NOx Emission Rate per Turbine and Duct Burner = 28.3 lbs/hr

NOx Emission Rate per Turbine and Duct Burner = 28.3 lbs/hr x ton/2000 lbs x 8760 hrs/yr
NOx Emission Rate per Turbine and Duct Burner = 124 tons/yr

6. CO Emissions from the Combustion Turbines and Duct Burners

CO Emission Rate of Combustion Turbine = 27.8 lbs/hr

CO Emission Rate of Duct Burner = 821.3 MMBtu/hr x 0.08 lb CO/MMBtu (Vendor Guarantee)
CO Emission Rate of Duct Burner = 65.7 lbs/hr

CO Emission Rate per Turbine and Duct Burner = 27.8 lb/hr + 65.7 lb/hr
CO Emission Rate per Turbine and Duct Burner = 93.5 lb/hr

Air Quality Modeling Analysis

Whiting Clean Energy, Inc. (Whiting), has requested a construction permit (CP 089-11194-00449) to construct and operate steam and electric power generation equipment adjacent to the BP Amoco Whiting Refinery in Lake County, Indiana. The Project comprises of two combustion turbine units with heat recovery steam generators (HRSG), a cooling tower and a condensing steam turbine generator. This site in Lake County is designated nonattainment for Ozone and portions of the county are Nonattainment for PM10 and SO2, while other portions of Lake County are nonattainment for CO.

The air quality impact analysis will accomplish the following objectives:

A. Establish which pollutants require an air quality analysis and provide analysis of stack height with respect to Good Engineering Practice (GEP)
B. Demonstrate that the source will not cause a violation of the National Ambient Air Quality Standards (NAAQS) or Prevention of Significant Deterioration (PSD) increment
C. Perform an analysis of any air toxic compound for the health risk factor on the general population.

RTP Environmental prepared the revision to Whiting's permit application. This was received by the Office of Air Management (OAM) on July 22, 1999. This document provides the Air Quality Modeling Section's review of the application.

Executive Summary

Whiting has asked to construct two combustion turbines, a cooling tower and a steam turbine generator at its Whiting facility. Portions of Lake County are non-attainment for PM10 and SO2. Lake county is classified as severe non-attainment for ozone. Lake county is attainment for all other pollutants. Modeling for PM10, NOx and CO shows that the project will not contribute to a violation of the NAAQS.

Part A

Pollutants Analyzed for Impact

The net change in emissions due to the project are listed in Table 1. The figures for each pollutant are the worst-case scenario for that pollutant.

Table 1
Change in Total Emissions in Tons per year due to Project

	PM10	SO2	NOx	CO	H2SO4	VOC	Lead
Combustion Turbines	158	8.9	161	243	1.22	24.3	0.01
Duct Burners	41.1*	2.4*	101*	328*	0.15*	45.2*	0.0021*
Cooling Tower	12.3	0	0	0	0	0	0
Primary Energy Increases	211.4	11.3	262	0	1.48	69.5	0.0121
Primary Energy Offsets	212	0	346	0	0	90.3	0
Net emission changes	-0.6	11.3	-80	571	1.37	-20.8	0.0121
De Minimus Levels	15	40	40	100	7	25	0.6

* Based on 5000 operating hours/year

For this new source's PSD permit, no modeling was performed for pollutants that did not have de minimus increases in emissions, namely H2SO4, Lead and SO2. No SO2 SIP sources have any increase in emissions due to this project.

No modeling was performed for sulfuric acid mist and VOC's due to their net emissions falling below de minimus levels. Primary performed modeling for CO and PM10 that was confirmed by IDEM, which demonstrated that no air quality standard violation would result in the non-attainment area. For PM10, inputs of the SIP inventories with the recently proposed changes were simulated. Pollutant concentrations were calculated at the PM10 SIP receptors.

Model Description

The OAM review used the Industrial Source Complex Short Term (ISCST3) model, Version 3, dated June 4, 1999 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the United States Environmental Protection Agency (U.S. EPA) approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models". The model also utilized the Schulman-Scire algorithm to account for building downwash effects. Stacks associated with the proposed merchant power facility are below the Good Engineering Practice (GEP) formula for stack heights. This indicates that wind flow over and around surrounding buildings can influence the dispersion of pollutant coming from the stacks. 326 IAC 1-7-3 requires a study to demonstrate that excessive modeled concentrations will not result from stacks with heights less than the GEP stack height formula. These aerodynamic downwash parameters were calculated using U.S. EPA's Building Profile Input Program (BPIP).

Class I Areas are federally designated areas such as wildlife areas and selected National Parks which are more sensitive to pollutant impacts. Additional modeling for the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas was not performed. This is due to the lack of any pollutant with De Minimus emission levels exceeding significant impact, and no Class I areas that exist within 100 kilometers of the project.

Load Screening Analysis

For the project, load screen modeling was performed to determine at which load percentages (50%,75% or 100%) and which temperatures (-10, 59,110) were the 'worst case' for CO, PM10 and NO2. This was determined by running the ISC model and examining the highest impacts using the most recent year (1995) of meteorological data.

Table 2
Worst Case Scenarios

Pollutant	Averaging Period	Temperature	Operating Load
NO2	Annual	59	50%
CO	1-hour	110	100%
CO	8-hour	110	100%
PM10	24-hour	110	50%
PM10	Annual	59	50%

Part B

Modeling for National Ambient Air Quality Standards

After the worst case scenario was identified, modeling to reveal the impact for Carbon Monoxide and Nitrous Oxides was run to determine whether further modeling was needed for those pollutants. For NO2, the majority of NOx emission from combustion sources is in the form of Nitric Oxide (NO), whereas EPA and IDEM have established air quality standards for NO2. EPA's Guideline for Air Quality Modeling provides a two-tiered approach to calculating the NO2 fraction of NOx emissions. Tier 1, the most conservative method assumes that all NOx emissions are in the form of NO2. Tier 2, is a national default ratio of 0.75, or a site specific ratio determined with a pre-construction program. Emissions were assumed to be Tier 2, 75% of total NOX emissions. This modeling showed that no significant impact would occur for either NOx or CO so no further modeling was performed for these pollutants. For a PSD source in an attainment area, a source with a non-significant impact will also not contribute to a violation of a standard for that pollutant.

Table 3
NO2 and CO Modeling Results

Pollutant	Time Period	Project's Impact	Year	UTM X Easting	UTM Y Northing	Significant Impact
CO	1-Hour	91	1993	4613.6	460.3	2000
CO	8-Hour	60	1993	4613.7	460.3	500
NO2	Annual	0.5	1991	4613.8	460.4	1

PM10

Level II modeling was performed for PM10. The ISCST results that were run with the 1995 meteorology were above Level II significance values (as shown below in Table 4) so Level III modeling was performed. No emission offset reductions have yet been determined (they will be required) so none were modeled as a conservative assumption.

The project's impact is greater than monitoring de minimus levels of 10 ug/m3. The project will operate on an AMOCO site that is currently monitored for PM10. The highest 24-hour reading during latest available three years was 47 ug/m3 and the highest annual reading was 24 ug/m3. Since the site is currently monitored, this monitor meets the preconstruction monitoring requirement (within 10 km of proposed emissions) of "Ambient Monitoring Guidelines for PSD" 2.4.1.

Table 4
PM10 Level II Modeling Results

Time Period (ug/m3)	Project's Impact (Ug/m3)	UTM X Easting	UTM Y Northing	Level II Significance (ug/m3)	Level II Significant Impact Area	Monitoring De Minimus
Annual	2.9	460340	4613410	1	281 meters	- - -
24-Hour	21.3	460340	4613410	5	1,562 metrers	10

Level III modeling was performed using the current Lake county SIP inventory and the project as sources. The sixth-highest readings within the Level II significant impact area were calculated from the 1991-1995 meteorological data.

Background PM10 values were the average of the six monitors in Lake county that have been operating during the latest three years. These were added to the sixth-highest 24-hour monitor values were used for calculations while the highest annual values were used. The highest sixth-highest impact for the five year period are listed in Table 5. The PM10 SIP receptors were used.

Table 5
PM10 Modeling Results

Time Period	Primary's Peak Impact (Ug/m3)	Countywide Peak Within Primary's Impact	Primary's Impact at Countywide Peak	Monitored Value	Total (Ug/m3)	NAAQS (Ug/m3)
Annual	2.9	80.6	0.5	20.9	101.5	50
24-Hour	21.3	218.3	0.0	35.2	253.5	150

Only four receptors were over the 24-hour standard that were also within the Level II significant impact area of the project. The sixth-highest modeled concentrations are listed in Table 6.

Table 6
PM10 Receptors over the 24-hour standard

UTM X Easting	UTM Y Northing	Modeled (Ug/m3)	Monitor (Ug/m3)	Total (ug/m3)	Standard (ug/m3)	Excess over Standard	Primary Contribution	Date YR/MM/DD
461000	4613400	209.4	35.2	244.6	150	94.6	0.0	93/09/16
461000	4613300	205.1	35.2	240.3	150	90.3	0.0	93/07/23
461000	4613500	116.5	35.2	151.7	150	1.7	0.0	93/09/16
461100	4613400	218.3	35.2	253.5	150	103.5	0.0	91/05/12

Only thirteen receptors were over the annual standard that were also within the Level II significant impact area of the project, which are listed in Table 7.

Table 7
PM10 Receptors over the annual standard

UTM X Easting	UTM Y Northing	Modeled (Ug/m3)	Monitor (Ug/m3)	Total (ug/m3)	Standard (ug/m3)	Excess over Standard	Primary Contribution	Year
461000	4613400	46.1	20.9	67.0	50	17.0	0.6	1994
461000	4613300	55.9	20.9	76.8	50	26.8	0.5	1995
461100	4613500	41.8	20.9	62.7	50	12.7	0.6	1994
461100	4613400	79.8	20.9	100.7	50	50.7	0.5	1994
461100	4613600	39.5	20.9	60.4	50	10.4	0.6	1994
461100	4613700	38.2	20.9	59.1	50	9.1	0.5	1994
461200	4613550	40.9	20.9	61.8	50	11.8	0.5	1994
461200	4613600	40.4	20.9	61.3	50	11.3	0.5	1994
461200	4613700	39.3	20.9	60.2	50	10.2	0.5	1993
461300	4613700	39.3	20.9	60.2	50	10.2	0.5	1994

These are small contributions in comparison to larger violations of the standard. PM10 monitoring values were obtained by taking the average of the monitors in Lake County that have data available for all of the last three years. For average calculations the 24-hour readings were taken from the highest second-highest from each monitor and the annual readings taken were the highest annual reading. No receptors are modeled above the standard due to the project.

Part C

Hazardous Air Pollutant Analysis and Results

OAM presently requests data concerning the emission of 188 Hazardous Air Pollutants (HAPs) listed in the 1990 Clean Air Act Amendments which are either carcinogenic or otherwise considered toxic. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Management's construction permit application Form Y. Any one HAP over 10 tons/year or all HAPs with total emissions over 25 tons/year will be subject to toxic modeling analysis. The modeled emissions for each HAP are the total emissions, based maximum hourly emissions, for a conservative assumption.

OAM performed HAP modeling using the ISCST3 model for all HAPs. Maximum 8-hour concentrations were determined and the concentrations were recorded as a percentage of each HAP Permissible Exposure Limit (PEL). The PELs were established by the Occupational Safety and Health Administration (OSHA). In Table 8 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAP are listed. All HAPs concentrations were modeled below 0.5% of their respective PELs. The 0.5% of the PEL represents a safety factor of 200 taken into account when determining the health risk of the general population.

Table 8
Hazardous Air Pollutant Modeling

Hazardous Air Pollutant	Plantwide Emissions Pounds/hour	Modeled 8-Hour Concentrations	PEL (Ug/m3)	Percent of PEL
Acetaldehyde	0.24	.066	360,000	.00001
Acrolein	0.08	.022	250	.0088
Benzene	0.044	.012	3,200	.00037
1,3 Butadiene	0.0004	.00011	2,200,000	.000000005
Dichlorobenzene	0.006	.00165	450,000	.00000036
Ethylbenzene	0.060	.0165	435,000	.000038
Formaldehyde	0.494	.137	930	.014
Hexane	3.78	1.050	1,800,800	.000058
Napthalene	0.007	.0019	50,000	.0000038
Toluene	0.248	.0689	750,000	.000009
Xylene	0.088	.0244	435,000	.0000056
Arsenic	0.0004	.00011	10	.0011
Beryllium	0.0001	.000028	2	.0014
Cadmium	0.006	.0017	5	.034
Chromium	0.006	.0017	500	.00034
Lead	0.0026	.00072	50	.0014
Manganese	0.0018	.00050	5,000	.00001
Mercury	0.0012	.00033	100	.00033
Molybdenum	0.0006	.00017	N/A	N/A
Nickel	0.0012	.00033	1,000	.000033
Selenium	0.00034	.00009	200	.000045

Conclusion

This modeling shows that the project will not contribute to any exceedence in the PM10 or SO2 non-attainment areas, and that no adverse health impacts would be expected from the project.

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) / LOWEST ACHIEVABLE EMISSION REDUCTION (LAER) REVIEW

The Office of Air Management (OAM) has performed the following federal BACT/LAER review for the proposed industrial steam and electric power co-generation plant to be owned and operated by Whiting Clean Energy, Inc. (Whiting), located in Whiting, Indiana. This review was performed for the two natural gas-fired combustion turbines and two natural gas-fired duct burners.

The source is located in an area of Lake County that is designated as attainment or unclassifiable for PM, NO_2, and CO. Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). PM, NO_2, and CO are subject to BACT review because the pollutant emissions are above the PSD significant threshold levels stated in 326 IAC 2-2-1. BACT is an emission limitation based on the maximum degree of reduction of each pollutant subject to the PSD requirements. In accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft USEPA *New Source Review Workshop Manual*, this BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause or contribute to air pollution thereby protecting public health and the environment.

The source is located in an area of Lake County that is designated as severe nonattainment for ozone (NOx and VOC) and nonattainment for PM10 and SO2. Therefore, these pollutants were reviewed pursuant to the Emission Offset Program (326 IAC 2-3). The pollutants of wzone (NO_X and VOC) are subject to LAER review because the pollutant emissions are above the significant threshold levels stated in 326 IAC 2-3-1(j). LAER is defined as the most stringent emissions limitation which is achieved in practice by a similar stationary source. Unlike BACT, LAER does not take into account the economic impacts associated with the control techniques. LAER is required to assure reasonable progress toward attainment of the NAAQS and to protect public health and the environment.

(A) Two Natural Gas-Fired Combustion Turbines and Two Natural Gas-Fired Duct Burners

The two combustion turbines will be General Electric Frame 7FA (Model 7241) models equipped with General Electric's dry low-NOx combustion systems. The heat input rating for each combustion turbine at ISO conditions is 1,735 MMBtu per hour. The hot combustion turbine exhaust will be ducted to its associated heat recovery steam generator, where the exhaust heat will be used to generate 1300 psig steam for electric power generation via the condensing steam turbine generator and refinery topping steam turbine generators. Auxiliary or supplemental duct firing is included as part of each combustion turbine/heat recovery steam generator. The rated heat input capacity of each duct burner is 821.3 MMBtu per hour. Auxiliary duct firing will be used to increase electric power production during periods of peak electric demand, and to maintain sufficient steam supplies for refinery use, when one of the two combustion turbines is shut down. Based on preliminary design information, the steam production from each heat recovery steam generator is estimated at 580,000 pounds per hour without duct firing and 1,188,000 pounds per hour with duct firing.

(1) PM BACT Review

There are three potential sources of filterable particulate emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter in the fuel for natural gas-fired combustion sources such as the proposed Whiting project. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to compression and use as combustion air in the combustion turbine. Finally, the potential for soot formation in a natural gas-fired combustion turbine with duct burners is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable particulate originating from either the turbine or duct burner.

There are two sources of condensible particulate emissions from combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the proposed Whiting project, there should be no condensible organics originating from the source because the main components of natural gas (i.e., methane and ethane) are not condensible at the temperatures found in a Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas-fired combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and in the ambient air is combusted and then cools.

Control Options Evaluated - The following control options were evaluated in the BACT/LAER review:

Fabric Filter
Electrostatic Precipitator
Wet Scrubber
Mechanical Collector

Technically Infeasible Control Options - All control options are technically infeasible because the only proposed fuel for this project is natural gas which has little to no ash that would contribute to the formation of PM or PM_{10}. The maximum expected loading of PM/PM_{10} from natural gas combustion for this project is 0.0039 grains per dry standard cubic feet at full load. In general, add-on particulate control systems can only control PM/PM10 to 0.01 grains per dry standard cubic feet.

Existing BACT/LAER Emission Limitations - The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for combustion turbines contains well over 100 entries. The following table represents the more stringent BACT/LAER emission limitations established for combustion turbines since 1990:

Company	Facility	Heat Input MMBtu/hr	PM/PM_{10} BACT/LAER Limitations (lb/MMBtu)	Compliance Status
Proposed Whiting Clean Energy, IN	GE Turbine	1735	0.0045	Not Yet Tested (5 and 202)
	Duct Burner	821	0.0045	
Lakewood Cogen, NJ	ABB GT11N Turbine	1073	0.0023	Compliant (201A&202)
Gordonsville Energy, VA	GE Frame 7(EA)Turbine	1430	0.0035*	Compliant (Method 5)
Duke Power Lincoln, NC	GE Frame 7 Turbine	1313	0.0038*	Compliant (201 or 201A)
CP&L Hartsville, SC	Westinghouse Turbine	1521	0.0039*	NonCompliant (Method 5)

Hardee Station, FL	GE PG7111(EA) Turbine	1268	0.0039*	None Specified
CP&L Goldsboro 1, NC	GE PG 7231(FA) Turbine	1908	0.0047*	Under Construction (201 or 201A)
CP&L Goldsboro 2, NC	GE PG7241(FA) Turbine	1819	0.0049*	Under Construction (201 or 201A)
Ecoelectrica L.P., PR	Westinghouse 501F Turbine	1900	0.0050*	Under Construction (201&202)
	Duct Burner	480		
Tiger Bay L.P., FL	GE PG7221(FA) Turbine	1700	0.0053	Test Not Required
	Duct Burner	100	0.01	
SMEPA-Mosell, MS	GE Frame 7(EA) Turbine	1299	0.0057*	Compliant (Method 5)
Saranac Energy, NY	GE PG7111(EA) Turbine	1123	0.0062*	Compliant (Method 5&19)
	Duct Burner	553	0.0027*	
Pilgrim Energy Center, NY	Westinghouse 501D5 Turbine	1400	0.007	Never Constructed
LSP- Cottage Grove, MN	Westinghouse 506G Turbine	1980	0.0089	Compliant (5&202)
	Duct Burner	278		
Union Carbide, LA	Westinghouse (8) Turbine	1313	0.009	No Test Specified
	Duct Burner	710		
Tiverton Power, RI	GE MS7001(FA) Turbine	1923	0.009	No Test Specified
Selkirk Cogen, NY	GE Frame 7(FA) Turbine	1173	0.014*	Compliant (Condensibles Not Tested)
	Duct Burner	206		
Georgia Gulf Corp, LA	GE NKV Turbine	1123	none	No Test Specified
	Duct Burner	450		

* These limits do not include condensible PM10 (Method 202)

Compliance with the particulate matter limits presented in the above table is demonstrated based on measurement of either the filterable particulate fraction only or the combined filterable and condensible particulate fractions. Because the majority if not all of the filterable particulate is PM10, and because vendor information indicates that at least half of the total particulate (i.e., filterable and condensible) is condensible, the limits based solely upon demonstrating compliance using only the filterable component were not considered representative for the purpose of comparison. As a result, these limits were eliminated from further review.

The Lakewood Cogeneration plant in New Jersey is only facility identified in the RBLC search that has a lower particulate limit than the proposed Whiting facility that demonstrated compliance based on the combined measurement of filterable and condensible particulate. The two ABB natural gas-fired turbines (1,073 MMBtu per hour, each) at the Lakewood Cogeneration plant demonstrated compliance with an emission limitation of 0.0023 pounds per MMBtu. This emission limitation was not used as BACT/LAER for the following reasons:

1. Different turbine manufacturers have been selected for the proposed Whiting facility and Lakewood facility. Each manufacturer has different combustion design technology that results in slight differences in pollutant limits. Although the PM limits from the ABB design is lower than the GE design, the corresponding NOx and CO emission limits are higher. Based on a review of this information, GE offers the best overall combustion design.

2. Limited performance testing was conducted for the Lakewood facility. Although Lakewood demonstrated compliance with its particulate emission limit, an evaluation of the test data indicates that a large enough sample volume may not have been collected to accurately conclude that the limit was demonstrated. This fact is further demonstrated by the level of variability between the filterable and condensible measurements between the three sampling runs. Therefore, the OAM determined that this compliance test is not representative for the purpose of transferring a limit from one manufacturer to another.

The particulate limit for the Whiting project is based on more accurate testing from a similar GE unit with an associated duct burner in Pasedena, Texas. Each test run was conducted such that a larger sample volume was collected to accurately reflect emissions. An evaluation of the data indicates that the condensible and filterable results from each run was consistent. Therefore, this information was used to establish a particulate emission limit from the turbines and duct burners of the proposed Whiting project.

<u>Conclusion</u> - Based on the information presented above, the PM BACT shall be the use of natural gas fuel. The turbines, with and without duct burner operation, shall be limited to 0.0045 pounds per MMBtu. The total PM emissions from each turbine shall not exceed 7.8 pounds per hour, and the total PM emissions from each turbine, when its associated duct burner is in operation, shall not exceed 11.5 pounds per hour.

(2) NO_2 BACT Review and NO_X LAER Review

Oxides of nitrogen (NOx) emissions from combustion turbines consist of two types: thermal NOx and fuel NOx. Thermal NOx is created by the high temperature reaction of nitrogen and oxygen in the combustion air. The amount formed is a function of the combustion chamber design and the combustion turbine operating parameters, including flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NOx formation is an exponential function of the flame temperature. Fuel NOx is formed by the gas-phase oxidation of char nitrogen. Fuel NOx formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the combustion oxygen levels. Natural gas contains a negligible amount of char nitrogen. As such, the only type of NOx formed by natural gas-fired combustion turbines and duct burners is thermal NOx.

Control Options Evaluated - The following control options and work practice techniques were evaluated in the BACT/LAER review:

Dry Low-NOx Burners
Water Injection
SCONOx System (Oxidation Catalyst)
Selective Catalytic Reduction
Selective Non-Catalytic Reduction
Non-Selective Catalytic Reduction

Technically Infeasible Control Options - Three of the control options listed above are not considered technically feasible: water injection, selective non-catalytic reduction, and non-selective catalytic reduction. Water injection, which is a NOx combustion control, is infeasible because it is not offered on the proposed combustion turbines for the purpose of NOx control. The combustion control included with the design of the proposed turbines is dry low-NOx burners. In some applications of dry low-NOx technology water injection is included as a means to generate increased power from the unit. However, the impact on NOx emissions associated with this water injection is that NOx emissions increase.

Selective non-catalytic reduction requires the addition of ammonia or a similar type selective reductant to an area where the temperature is in the 1500 to 2000°F range. There is no operating range associated with the proposed combustion turbines that meets these requirements. The exhaust temperature at the turbine exit is in the 950 to 1050°F range during normal operation.

Non-selective catalytic reduction is the catalytic approach used to control NOx emissions from mobile sources such as cars. For this approach to work, the combustion process is run fuel rich in order to generate unburned hydrocarbon radicals. These compounds then serve as the non-selective reactant for the NOx reduction reactions. An additional oxidation catalyst is then required behind the reduction catalyst to complete the oxidation process so that VOC emissions are not increased. Use of this approach is not considered technically feasible because the combustion turbines dry low-NOx system is not designed to operate in a fuel rich mode. In addition, this approach increases the likelihood of additional VOC emissions from the process.

Ranking of Technically Feasible Control Options - The following technically feasible nitrogen oxide control technologies were ranked by control efficiency:

Rank	Control	Facility	Control Efficiency (%)	Emission Limit (ppm)
1	Dry Low-NOx Burners	Turbine	N/A	9-15
		Duct Burner	N/A	20-30
2	SCONOx (for large turbine units with Dry Low-NOx Burners)	Turbine	90+	2.0-4.5
		Duct Burner	90+	2.0-4.5
3	Selective Catalytic Reduction (for large combustion units with Dry Low-NOx Burners)	Turbine	80-90+	2.5-4.5
		Duct Burner	80-90+	2.5-4.5

Discussion - The dry low-NOx burners are an integral design feature of the combustion turbines. Based on the GE vendor specifications, the combustion turbines can achieve an emission limit of 9 ppm and the duct burners can achieve an emission limit of 0.08 pounds per MMBtu. The *"Top-Down" Best Available Control Technology Guidance Document* states that combinations of inherently lower emitting processes and add-on controls must be investigated as part of the BACT review.

The SCONOx system is a new flue gas clean up system that uses a coated oxidation catalyst to remove both NOx and CO. The oxidation catalyst oxidizes CO to CO2 and NOx to NO_2. The NO_2 is then absorbed onto a potassium carbonate coated catalyst. Because the potassium carbonate coating is consumed as part of the absorption step it must be frequently regenerated. To regenerate the potassium coating it is contacted with a reducing gas (CO and H_2) made from natural gas. During regeneration flue gas dampers are used to isolate a section of the coated catalyst from the flue gas path so that the regeneration gases can be contacted with the catalyst. At this time, the SCONOx system has only been applied on small industrial, cogeneration turbines. The louver/valving system used during the regeneration step to isolate the catalyst from the exhaust gas flow requires a complete redesign before the system can be scaled up for use on units larger than that which it is currently operating (i.e., 25 MW). There are long term maintenance and reliability concerns related to the mechanical components on the large scale turbine projects.

The SCR system is a post combustion control technology in which injected ammonia reacts with NOx in the presence of a catalyst to form water and nitrogen. The level of NOx emission reduction is a function of the catalyst volume and ammonia-to-NOx ratio. For a given catalyst volume, higher NH3/NOx ratios can be used to achieve higher NOx emission reductions but can result in undesired increased levels of unreacted NH3.

<u>Existing BACT/LAER Emission Limitations</u> - The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for combustion turbines contains well over 100 entries. The following table represents the more stringent BACT/LAER emission limitations established for similar sized combustion turbines since 1990:

Company	Facility Size	NOX Control Equipment	NOX BACT/LAER Limits (ppmvd)	Status
Proposed Whiting Clean Energy	2x2556 MMBtu/hr CTs/DBs	DLN + SCR	3.0 (3-hr rolling avg)	Proposed
Cabot Power Corp, MA	350 MW	DLN + SCR	2.0 (1-hr avg)	Permitted
Mystic Station, MA	275 MW	DLN + SCR	2.0 (1-hr avg)	Permitted
Otay Mesa Power,CA	510 MW	DLN +SCONOx	2.0 (3-hr block)	Proposed
LaPaloma Power, CA	262 MW	DLN + SCR	2.5 (1-hr avg)	Permitted
Gorham Energy Limited, ME	3x300 MW CTs/DBs	DLN + SCR	2.5 (3-hr block avg)	Permitted

Westbrook Power, ME	2x264 MW CTs	DLN + SCR	2.5 (3-hr block avg)	Permitted
Sunlaw Cogeneration, CA	32 MW CT	WI + SCONOx	2.5 (annual avg)	Operating
SPA Campbell Soup, CA	1257 MMBtu/hr CT/DB	DLN + SCR	3.0 (3-hr block avg)	Operating
CASCO Ray Energy, ME	2x170 MW CTs	DLN + SCR	3.5 (3-hr block avg)	Permitted
Brooklyn Navy Yard Cogen, NY	2x120 MW CTs	DLN + SCR	3.5 (1-hr avg)	Operating
Wood River Refinery Cogen, IL	3x211 MW CTs/DBs	DLN + SCR	3.5 (24-hr avg)	Permitted
Alabama Power - Theodore Cogen, AL	170 MW CT/DB	DLN + SCR	3.6 (3-hr avg)	Permitted
Blue Mountain Power, PA	153 MW CT/DB	DLN + SCR	4.0	Never Built
Wyandotte Energy, MI	500 MW CT/DB	DLN + SCR	4.5	Permitted
LSP-Cottage Grove, MN	1988 MMBtu/hr CT/DB	DLN + SCR	4.5	Operating
Sithe/Independence Power, NY	4x2133 MMBtu/hr CTs	DLN + SCR	4.5	Operating
Peoples Gas/ McDonnell Energy, IL	10x250 MW CTs	DLN + SCR	4.5	Permitted

Based on the RBLC review and information obtained from other states, there are three facilities that have been permitted with a 2.0 ppm emission limit; however, none of these facilities have been constructed. There are four facilities that have been permitted with a 2.5 ppm emission limit; however, only one facility (Sunlaw Cogeneration in California) is operating. These emission limitations were not used as LAER for the following reasons:

1. Although there have been several facilities permitted with a limit of 2.0 ppm, none have begun operating and as such, there is no compliance data to support that these facilities can comply with the permitted limit.

2. Although there have been four facilities permitted with a limit of 2.5 ppm, only one (Sunlaw Cogeneration) has begun operation. The NOx CEM data for Sunlaw Cogeneration supports that the unit is achieving the 2.5 ppm limit over a 3-hr block average utilizing SCONOx to control NOx emissions. However, this unit is not comparable because it is much smaller (32 MW) than the proposed turbine project (166 MW). For large scale projects such as the proposed Whiting Clean Energy project, there are long term maintenance and reliability concerns related to the mechanical components of the SCONOx system.

In addition to the reasons stated above, the averaging times associated with the limits should also be evaluated to determine the more stringent limit. Four of the seven facilities with a 2.0 ppm or 2.5 ppm emission limit have less stringent averaging times. One of these facilities, Sunlaw Cogeneration, has a 2.5 ppm limit, but the averaging time is on an annual basis. This averaging time allows the facility much flexibility in its operating practices. For example, the facility may operate much higher than 2.5 ppm on a short term basis, but still manage compliance from a long term (annual) basis.

The other three facilities have a 3-hour block averaging time which is less stringent than a 3-hour rolling average. The 3-hour rolling average, which is the proposed averaging time for the Whiting project, is more restrictive than the 3-hr block because each hourly reading is utilized three times over the 3-hour rolling average. For example, if there is one high hourly reading it is evaluated in the compliance demonstration 3 times. This differs from the 3-hour block average which evaluates the same high hourly reading only once to demonstrate compliance within that "block" of time. Therefore, with the 3-hour rolling average there is the possibility that the unit is out of compliance for three readings versus only one reading if it were evaluated on a 3-hour block average.

With respect to the remaining three facilities, the averaging time is based on a 1-hour average. This averaging time may be more or less restrictive than the 3-hour rolling average. With the 1-hour average there is less flexibility to demonstrate compliance; however, each hourly reading is only evaluated once. The 3-hour rolling average does allow more flexibility, but if there is one high reading it will be evaluated for compliance three times. Regardless of this exercise, there is no long term data to support that the 2.0 ppm or 2.5 ppm limit is achievable.

Based on the RBLC review and information obtained from other states, there is one facility that was permitted with a 3.0 ppm emission limit with a 3-hour block averaging time. The SPA Campbell Soup facility has been in operation for approximately 2 years. The OAM obtained the CEM data for this facility, included in Appendix C-1, to evaluate the emission rates from the turbine. Based on CEM data collected from the last quarter of 1997 through 1999, the average 3-hour rolling emission rate is approximately 2.5 ppm. It should be noted that as the catalyst degrades with time, the system may become less efficient. Because there is only 2 years of data available for the SPA Campbell Soup facility, it is not known how the emission rate will change as the catalyst ages.

The proposed emission limit of 3.0 ppm is based on normal turbine operation. Normal operation is achieved when the turbine is operating at 50 percent load or more. During periods of startup or shutdown (less than 50 percent load), different emission limitations for combustion pollutants (CO and NOx) have been established in the permit. Because the GE Model 7241 is a new design, these limitations are based on information provided by the manufacturer. The emissions are greater during periods of startup and shutdown because the dry low-NOx system cannot sustain stable operation at loads below this and because time is required to bring the HRSG up to the SCR's required operating temperature. Short-term emissions increases due to startup and shut down do not impact the amount of annual emissions associated with the project because of the non-emitting periods associated with unit downtime.

Conclusion - Based on the information presented above, the NOx BACT/LAER shall be the use of the low-NOx burner design in conjunction with the SCR control with an emission limit of 3.0 ppm based on a 3-hour rolling average during normal operation. This emission limit is equivalent to 19.5 pounds NOx per hour for each combustion turbine and 38.0 pounds NOx per hour for each combustion turbine, when its associated duct burner is in operation. During periods of startups or shutdowns (less than 50 percent load), the NOx emissions from each combustion turbine stack shall not exceed 70 ppmvd at 15 percent oxygen. The startup or shutdown period shall not exceed two (2) hours. The duct burners shall not be operated until normal operation begins.

(3) VOC LAER Review

The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and/or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines and duct burners incorporate state-of-the-art combustion technology which are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

Control Options Evaluated - The following control options and work practice techniques were evaluated in the LAER review:

Thermal Oxidation
SCONOx (Oxidation Catalyst)
Good Combustion Design and Operation

Technically Infeasible Control Options - Thermal oxidation, which includes flares, post combustion reaction chambers, duct burners, and thermal incinerators have been proven technologies. Because of the low VOC concentration generated from the use of natural gas and state-of-the-art combustion technology, the thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas which in turn would generate additional VOC and NOx emissions. Therefore, this technology is considered infeasible for the proposed project. It should be noted that duct burners are proposed downstream of the combustion turbines. These duct burners allow the system to generate additional power and steam during peak demand.

Ranking of Technically Feasible Control Options - The following VOC control technologies were ranked by control efficiency:

Rank	Control	Control Efficiency (%)
1	Oxidation Catalyst	70-90+
2	Good Combustion Design and Operation	N/A

Discussion - VOC emissions from natural gas-fired combustion sources are the result of incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of time, temperature, and turbulence. Combustion control techniques are used to maximize fuel efficiency and to ensure complete combustion. State-of-the-art combustion control techniques are inherent in the design features on the proposed combustion turbines and duct burners. These combustion control techniques lower the VOC concentrations to levels below which an oxidation catalyst effectively removes additional VOC emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon (of which a portion is VOC) to CO2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion is 950-1050°F. Operation at temperatures above 1150°F thermally degrades the catalyst, while the operation at temperatures below 950°F decreases the catalyst performance. For projects that include duct firing, such as the proposed Whiting facility, the oxidation catalyst's placement is driven by the duct burner's rated capacity. However, the catalyst is only effective when the duct burner is in operation because the temperature regime changes (decreases to about 800°F) when the duct burner is not fired.

Existing BACT/LAER Emission Limitations - The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for combustion turbines contains well over 100 entries. The following table represents the more stringent BACT/LAER emission limitations established for similar sized combustion turbines since 1990:

Company	Facility	Heat Input MMBtu/hr	VOC BACT/LAER (lb/MMBtu)	Control/ Compliance
Proposed Whiting Clean Energy, IN	Turbine	1735	0.0016 (1.4 ppm) (2.8 lbs/hr)	Combustion Controls
	Duct Burner	821	0.011 (0.0046 CT+DB)	Combustion Controls
Gorham Energy, ME	Turbine	2194	0.0017	Oxidation Catalyst/ Permit Pending
Saranac Energy, NY	Turbine	1123	0.0045	Oxidation Catalyst/ Operating
	Duct Burner	553	0.011	
Blue Mountain Power, PA	Turbine	1440	0.0076	Oxidation Catalyst/ Never Built
	Duct Burner	185		
CP&L Goldsboro, NC	Turbine GE 7FA	1908	0.0015	Combustion Control/ Under Construction
Duke Power Lincoln, NC	Turbine	1247	0.004	Combustion Controls/ Operating
Duke Power Lincoln, NC	Turbine GE 7EA	1313	0.0015	Combustion Controls/ Operating
Tiger Bay Cogen, FL	Turbine	1896	0.0016	None Specified/ Operating
TECO Polk CO, FL	Turbine	1755	0.0017	Combustion Control/ Not Specified

FP&L Lavogrome, FL	Turbine	1632	0.0017	Combustion Control/ Not Specified
	Duct Burner	91		
Alabama Power & Light	Turbine	1777	0.016	Combustion Control
	Duct Burner			
Ecoelectrica LP, PR	Turbine	1900	0.0073	Combustion Control/ Under Construction
	Duct Burner	480		
Narragansett Electric, RI	Turbine	1360	5 ppm	Combustion Control
	Duct Burner			
Champion International, ME	Turbine	175 MW	3 lb/hr gas	Combustion Control/ Below PSD (40 tpy)
Casco Ray Energy, ME	Turbine	170 MW	1 ppm	Combustion Control/ Below PSD (40 tpy)
Westbrook Power, ME	Turbine	264 MW	0.4 ppm	Combustion Control/ Below PSD (40 tpy)
Lakewood Cogeneration, NJ	Turbine	1190	0.0046	Combustion Control
	Duct Burner	131	0.0017	
Pilgrim Energy Center, NY	Turbine	1400	0.002	No Controls/ Never Built
	Duct Burner	214	0.016	

As shown in the above table, there are four turbine projects with more stringent VOC emission limits than the proposed Whiting project. The OAM divided these facilities into two categories to compare and evaluate these VOC emission rates to the proposed Whiting VOC emission rate:

1. Facilities with Different Turbine Models:

   Duke Power Lincoln, North Carolina
   CP&L Goldsboro, North Carolina

   The VOC emission rates from Duke Power Lincoln in North Carolina and CP&L Goldsboro in North Carolina (both limited to 0.0015 lb/MMBtu) are slightly lower than the VOC emission rate from the proposed Whiting facility (0.0016 lb/MMBtu). The slight emission difference between the Duke Power Lincoln facility and the proposed Whiting facility is due to the turbine size difference. Although the VOC concentration is slightly lower for the CP&L Goldsboro facility, the VOC emission rate (2.8 pounds per hour) is the same as the proposed Whiting facility. This difference is due to site specific/combustion turbine model year heat input. For both Duke Power and CP&L Goldsboro the VOC limits are lower than the proposed Whiting facility; however, the corresponding NOx and CO emission limits are higher:

Facility	VOC Emission Limit (lb/MMBtu)	NOx Emission Limit (ppm)	CO Emission Limit (ppm)
Proposed Whiting	0.0016	9	9
CP&L Goldsboro, NC	0.0015*	25	25
Duke Power Lincoln, NC	0.0015	25	25

Based on a review of this information, the proposed Whiting facility offers the best overall combustion design.

2. Facilities with Operational Restrictions to Avoid PSD BACT Review:

   Casco Ray Energy, Maine
   Westbrook Power, Maine

   Although the VOC limitations for Casco Ray Energy in Maine and Westbrook Power in Maine are lower than the proposed Whiting facility, these VOC limitations are based on operational limitations to avoid PSD requirements. Because of these operational restrictions, the VOC limitations associated with these two facilities are not comparable to the proposed Whiting project.

With regard to the duct burner, the proposed Whiting facility is proposing the lowest VOC emission rate (0.011 pounds per MMBtu at rated load) achievable in practice for similar sized facilities as identified in the RBLC. Therefore, no further analysis is necessary.

With regard to the facilities listed in the RBLC that have combined limits for the combustion turbine and duct burner, the OAM calculated the combined limit for the proposed Whiting facility (0.0046 pounds per MMBtu). FP&L in Florida is the only similar sized facility that has a lower combined limit (0.0017 pounds per MMBtu).

The duct burners at the FP&L facility is much smaller (91 MMBtu per hour) than the duct burner at the proposed Whiting facility (821 MMBtu per hour). Because of this difference, the emission limitation for the FP&L facility is not comparable and shall not be used in the emission limit determination for the Whiting project.

Conclusion - Based on the information presented above, each combustion turbine at the proposed Whiting facility shall be limited to 0.0016 pounds VOC per MMBtu, which is equivalent to 2.8 pounds per hour. Each turbine, when its associated duct burner is in operation, shall not exceed 0.0046 pounds VOC per MMBtu, which is equivalent to 11.8 pounds per hour.

(4) CO BACT Review

Carbon monoxide is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NOx during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions.

However, improved air/fuel mixing inherent in newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluated - The following control options and work practice techniques were evaluated in the BACT review:

Oxidation Catalyst
SCONOx
Good Combustion Design and Operation

Ranking of Technically Feasible Control Options - The following CO control technologies were ranked by control efficiency:

Rank	Control	Control Efficiency (%)	Emission Limit, lb/MMBtu
1	SCONOx (with good combustion design)	95	0.0005-0.001
2	Oxidation Catalyst (with good combustion)	90	0.001-0.002
3	Good Combustion Design and Operation	n/a	0.01-0.02

Discussion - CO emissions from natural gas-fired combustion sources are the result of incomplete combustion. Complete combustion is a function of time, temperature, and turbulence. Combustion control techniques are used to maximize fuel efficiency and to ensure complete combustion. State-of-the-art combustion control techniques are inherent design features on the proposed combustion turbines and duct burners for the proposed Whiting project.

The combustion design techniques are an inherent design feature of the combustion turbines and duct burners. The *"Top-Down" Best Available Control Technology Guidance Document* states that combinations of inherently lower emitting processes and add-on controls must be investigated as part of the BACT review.

The SCONOx system is a new flue gas clean up system that uses a coated oxidation catalyst to remove both NOx and CO. The oxidation catalyst oxidizes CO to CO2 and NOx to NO2. The NO2 is then absorbed onto a potassium carbonate coated catalyst. Because the potassium carbonate coating is consumed as part of the absorption step it must be frequently regenerated. To regenerate the potassium coating it is contacted with a reducing gas (CO and H2) made from natural gas. During regeneration flue gas dampers are used to isolate a section of the coated catalyst from the flue gas path so that the regeneration gases can be contacted with the catalyst. At this time, the SCONOx system has only been applied on small industrial, cogeneration turbines. The louver/valving system used during the regeneration step to isolate the catalyst from the exhaust gas flow requires a complete redesign before the system can be scaled up for use on units larger than that which it is currently operating (i.e., 25 MW). There are long term maintenance and reliability concerns related to the mechanical components on the large scale turbine projects.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO to CO_2. This technology has been applied to natural gas-fired combustion turbines of all sizes and as such is considered a demonstrated technology. For units that include duct firing, such as the proposed Whiting facility, the placement of the catalyst is defined by the need to protect it from temperatures in excess of 1100°F. Because the removal efficiency of CO is fairly constant above 800°F, there is only minimal impact to the catalyst's performance associated with placing the catalyst further back in the HRSG.

Existing BACT Emission Limitations - The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for combustion turbines contains well over 100 entries. The following table represents the more stringent BACT/LAER emission limitations established for combustion turbines since 1990:

Company	Facility	Heat Input MMBtu/hr	CO BACT/LAER Limitations (lb/MMBtu)	Control/ Compliance
Proposed Whiting Clean Energy, IN	Turbine	1735	0.016 (9 ppm)	Good Combustion
	Duct Burner	821	0.08 (19 ppm)	
Wyandotte Energy, MI	Turbine	500 MW	3 ppm	Oxidation Catalyst
Saranac Energy, NY	Turbine	1123	3 ppm	Oxidation Catalyst
	Duct Burner	553	0.06	
Blue Mountain Power, PA	Turbine	153 MW	3.1 ppm	Oxidation Catalyst (Never Constructed)
Brooklyn Navy Yard, NY	Turbine	240 MW	4 ppm	Oxidation Catalyst
Gorham Energy, ME	Turbine	2194	5 ppm	Oxidation Catalyst
Pasny/Holtsville Plant, NY	Turbine	1146	8.5 ppm	Good Combustion
Savannah Electric and Power, GA	Turbine	1032	9 ppm	Good Combustion
Champion Intl, ME	Turbine	175 MW	9 ppm	Good Combustion
EEX Power, WA	Turbine	123 MW	10 ppm	Good Combustion
Unocal, CA	Turbine		10 ppm	Oxidation Catalyst
Bridgeport Energy, CT	Turbine	260 MW	10 ppm	Good Combustion
Mid-Georgia Cogen, GA	Turbine	116 MW	10 ppm	Good Combustion
Belkirk Cogen, NY	Turbine	1173	10 ppm	Good Combustion
	Duct Burner	206	0.072	
Pilgrim Energy, NY	Turbine	1400	10 ppm	Good Combustion
	Duct Burner	214	0.106	
Narragansett Electric, RI	Turbine	1380	11 ppm	Good Combustion

	Duct Burner	98	11 ppm	
Bithe/Ind Power, NY	Turbine	2133	13 ppm	Good Combustion
Westbrook Power, ME	Turbine	525 MW	15 ppm	Good Combustion
Dighton Power, MA	Turbine	1327	0.0046	Good Combustion
Grays Ferry Co, PA	Turbine	1150	0.0066	Good Combustion
Berkshire Power, MA	Turbine	1792	0.008	Good Combustion
US Alliance, AL	Turbine+DB		0.068	Good Combustion

As shown in the above table, there are nine turbine projects with more stringent CO emission limits than the proposed Whiting project. All but one of those projects utilize an oxidation catalyst to reduce CO emissions. The following table represents a more detailed review of each of these projects:

Company	Attainment Status	Control	CO Inlet Emissions	CO Outlet Emissions	Economic Evaluation (Cost/Ton)
Proposed Whiting Clean Energy, IN	Attainment	Good Combustion	9 ppm	9 ppm (0.016 lb/MMBtu)	N/A
		Oxidation Catalyst	9 ppm	3 ppm	2500
Wyandotte Energy, MI	Nonattainment	Oxidation Catalyst	N/A	3 ppm	N/A
Saranac Energy, NY	Attainment; Nonattainment for O_3	Oxidation Catalyst	N/A	3 ppm	N/A
			N/A	0.06	N/A
Blue Mountain Power, PA	Attainment; Nonattainment for O_3	Oxidation Catalyst	N/A	3.1 ppm	N/A
Brooklyn Navy Yard, NY	Nonattainment	Oxidation Catalyst	N/A	4 ppm	N/A
Gorham Energy, ME	BACT	Oxidation Catalyst	25 ppm	5 ppm	1200
Pasny/Holtsville Plant, NY	Nonattainment	Good Combustion	N/A	8.5 ppm	N/A
Dighton Power, MA	Attainment; Nonattainment for O_3	Oxidation Catalyst	25 ppm	0.0046 lb/MMBtu (2 ppm)	N/A
Grays Ferry Co, PA	Nonattainment	Oxidation Catalyst	25 ppm	0.0055 lb/MMBtu (3 ppm)	N/A

Berkshire Power, MA	Attainment; Nonattainment for O_3	Oxidation Catalyst	25 ppm	0.008 lb/MMBtu (4.5 ppm)	N/A

The OAM divided the facilities listed in the above table into three categories to compare and evaluate these CO emission rates to the proposed Whiting CO emission rate:

1. Facilities Located in CO Nonattainment Areas:

    Wyandotte Energy, Michigan
    Brooklyn Navy Yard, New York
    Pasny/Holtsville Plant, New York
    Grays Ferry Co, PA

    The facilities listed above are located in CO nonattainment areas and are subject to the Emission Offset LAER requirements. The proposed Whiting facility is located in a CO attainment area and is subject to the PSD BACT requirements. Unlike BACT, LAER does not take into account the economic impacts associated with the control techniques. A BACT analysis was performed for the proposed Whiting facility as described below to determine if an oxidation catalyst is economically feasible. Due to the economic factors associated with the BACT review, the above LAER determinations can not be directly compared to the proposed Whiting project.

2. Facilities Located in Ozone Nonattainment Areas:

    Saranac Energy, New York
    Blue Mountain Power, Pennsylvania
    Berkshire Power, MA
    Dighton Power, MA

    The oxidation catalyst was applied to these projects to control VOC emissions (a precursor for the formation of ozone). As a result, the CO emissions are also reduced by the oxidation catalyst. Prior to the application of an oxidation catalyst, the VOC concentration from the proposed Whiting facility is considerably lower than the VOC concentrations from the above listed facilities due to the combustion control techniques applied. The combustion control techniques applied to the proposed Whiting facility lower the VOC concentrations to levels below which an oxidation catalyst effectively removes additional VOC emissions. Because the VOC emission rate from the proposed Whiting facility is lower than the above listed facilities, an oxidation catalyst is not required for the proposed Whiting facility.

3. Facilities Located in CO Attainment Areas:

    Gorham Energy, Maine
    Berkshire Power, MA
    Dighton Power, MA

An oxidation catalyst was applied to each of these projects because each CO cost analysis was economically feasible ($1000-1200/ton CO removed). The CO cost analysis of an oxidation catalyst on the proposed Whiting facility was economically infeasible ($2500/ton CO removed), which is consistent with other recent decisions made. The cost difference between these facilities is a result of the higher inlet CO emissions. Prior to the application of an oxidation catalyst, the CO concentration from the proposed Whiting facility (9 ppm) is considerably lower than the CO concentrations from the above listed facilities (25 ppm) due to the combustion control techniques applied. The combustion control techniques applied to the proposed Whiting facility lower the CO concentrations to levels below which an oxidation catalyst is economically feasible. The detailed CO Cost Analysis for the proposed Whiting facility is included in Appendix C-2.

Conclusion - Based on the information presented, the CO BACT shall be the use of natural gas and combustion control design. Each combustion turbine shall not exceed 0.016 pounds CO per MMBtu which is equivalent to 28.0 pounds per hour and each combustion turbine, when its associated duct burner is in operation shall not exceed 0.037 pounds CO per MMBtu which is equivalent to 93.7 pounds per hour.

(B) Cooling Tower

Evaporative cooling towers are designed to cool process cooling water by contacting the water with air, and evaporating some of the water. Thus, these units use the latent heat of water vaporization to exchange heat between the process and the air passing through the tower. This type of cooling tower typically contains a wetted medium to promote evaporation, by providing a large surface area and/or by creating many water drops with a large cumulative surface area. Some of the liquid water may be entrained in the air stream and be carried out of the tower.

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower evaporate, and the dissolved and suspended solids within these droplets become airborne. Particulate emissions from towers are controlled by installing drift eliminators, devices that are designed to minimize total liquid drift (dissolved solids on water droplets from evaporative cooling towers).

(1) PM BACT Review

Control Options Evaluated - The only control option evaluated in the BACT/LAER review for the cooling tower was drift eliminators. This is consistent with similar operations.

Existing BACT/LAER Emission Limitations - The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents the more stringent BACT/LAER emission limitations established for combustion turbines since 1990:

Company	Facility	Control	Total Liquid Drift (% flow)	PM/PM_{10} BACT/LAER Limitations (lb/hr)	Compliance Status
Proposed Whiting Clean Energy, IN	Cooling Tower	High Eff Drift Eliminators	0.001	3.63	N/A
Ecoelectrica LP, PR	Cooling Tower	2-Stage Drift Eliminator	0.0015	60	None Required

Lakewood Cogen, NJ	Cooling Tower	Drift Eliminator	0.002	0.874	None Required
Crystal River, Units 1, 2, 3, FL	Cooling Tower	High Eff Drift Eliminator	0.004	428	None Required
Crystal River, Units 4, 5, FL	Cooling Tower	High Eff Drift Eliminator	----	175	None Required
Texaco Bakersfield, CA	Cooling Tower	Cellular Type Drift Eliminator	----	1.26	None Required
Crown/Vista Energy, NJ	Cooling Tower	Drift Eliminator	0.1	5.9	None Required

Emissions of particulate matter from cooling towers are mainly caused by dissolved solids within the water droplets (drift) that escape the tower. The particulate matter is generated when escaped droplets evaporate and the suspended and dissolved solids are left behind. The concentration of total dissolved solids (TDS) in different cooling waters varies widely and is site dependent. For the Whiting project, because the water is noncontact cooling water the amount of TDS is not a result of the process it is cooling. Instead, it is a function of the cooling water source, Lake Michigan.

For a given solids concentration (defined by the cooling water source and tower design and operating specifications), particulate emissions from cooling towers depend on the amount of water that drifts from the tower. The amount of drift from evaporative cooling towers, usually expressed as a percent of circulating water flow, is called total liquid drift. Total liquid drift is controlled by drift eliminators installed in the tower cells. Drift eliminators work by passing the cooling tower exhaust through mesh type media resulting in the inertial separation of water droplets (mist) from the air stream.

As shown in the above table, a search of the available cooling tower particulate permit information revealed that different types of cooling towers are permitted, including mechanical draft, wet/dry and hyperbolic towers. Permitted towers range in size from 18,000 gallons per minute fresh water units (Texaco Bakersfield) to 331,000 gallons per minute sea water units (Crystal Power Station). These cooling towers use various types of drift eliminators, rated from 0.00154 to 0.1 percent total liquid drift, to control particulate emissions.

The proposed Whiting facility is proposing the lowest total liquid drift rate of 0.001 percent. Therefore, no further analysis is necessary.

<u>Conclusion</u> - Based on the information presented above, the PM BACT shall be the use high efficiency drift eliminators of each cooling tower cell. The total liquid drift rate shall not exceed 0.0015 percent. Based on the water source, the total particulate emissions from the cooling towers shall not exceed 3.63 pounds per hour.

Summary of Statistics Calculated for 3-Hour Averages of NO_x Data Reported by Sacramento Power Authority – Campbell Soup Cogeneration Facility

Quarter/Year	Range of 3-hr Averages	Mean	Standard Deviation	Median
4th of 1997	0.20 – 8.533	2.254	0.494	2.333
1st of 1998	1.20 – 10.60	2.284	0.402	2.30
2nd of 1998	1.033 – 3.933	2.220	0.218	2.267
3rd of 1998	1.167 – 5.20	2.425	0.217	2.433
4th of 1998	1.367 – 10.40	2.458	0.301	2.433
1st of 1999	1.533 – 5.30	2.328	0.140	2.333
2nd of 1999	1.30 – 5.60	2.234	0.201	2.233
3rd of 1999	1.567 – 5.633	2.355	0.182	2.367
4th of 1999	1.467 – 13.667	2.551	0.285	2.50

Notes:
- Data were obtained from the U.S. EPA Acid Rain web site.
- The 3-hour averages used in calculating the above statistics do not include missing data (i.e., zeros).